CANADA

National Energy Board

Reasons for Decision

TransCanada PipeLines Limited

GH-5-89

April 1991

Volume 3
Facilities, Gas Exports and
Section 71 Applications

ERRATA

NATIONAL ENERGY BOARD

Reasons for Decision
in the matter of an application from
TransCanada PipeLines Limited for
1991 and 1992 Facilities and Associated Part VI and
Section 71 Applications

Volume 3 - Facilities, Gas Exports and Section 71 Applications

GH-5-89

1. Please replace pages 239 to 241 of the report with the attached.

2. On page xii of the Table of Contents, Sections 20.4 and 20.5 should read "20.3.4" and "20.3.5" respectively; on page 165, Section 20.4 should read "20.3.4"; and on page 167, Section 20.5 should read "20.3.5".

3. In Table 2-1, reference to "system system" in item 4 should read "system supply" and "Elizabethown" in item 15 should read "Elizabethtown".

4. In Table 3-1, the footnote reference following Pawtucket should read "[1]" and not "171".

5. On page 115, second column, second full paragraph, there should be a period after "initial 20-year term", instead of a comma.

6. On page 120, second column, last paragraph - reference to "chapter 27 in these Reasons" should read "chapter 26 in these Reasons".

7. On page 146, footnote #1 should read "Canadian Energy Supply and Demand, 1987-2005" and not "... 1987-2000".

8. On page 158, last two paragraphs of the second column, page 160 and Table 20-4, references to "EIA" should read "Energy Information Administration (U.S.)".

9. On page 159, reference to Table 20-5 in the footnote should read "Table 20-3".

10. In Appendix IV, please change the following:

    (i) Pawtucket Power Associates Limited Partnership

    Under condition 2 (c), read "1 986 000 000 cubic metres" instead of "1 986 000 cubic metres".

(ii) **Encogen Four Partners, L.P.**

Under condition 2, read "The quantity of gas..." instead of "Subject to condition 3, the quantity of gas..."; and

Under condition 3, read "Gas exported... to the point of export near Chippawa, Ontario." instead of "Gas exported... to the point of export near Niagara Falls, Ontario.".

(iii) **FSC Resources Limited**

Under condition 5, read "... replace either its gas supply or market with other gas supplies or markets." instead of "... replace either its gas supply or market with other gas supply or market.".

(iv) **Selkirk Cogen Partners, L.P.**

Under condition 1, read "... or the date of first deliveries, whichever is the later, and shall end..." instead of "... or the date of first deliveries and shall end...".

(v) **Kamine Carthage Cogen Co., Inc. and Beta Carthage Inc.**

Under condition 2 (c), read "2 093 700 000 cubic metres" instead of "2 093 700 cubic metres".

(vi) **Kamine South Glens Falls Cogen Co., Inc. and Beta South Glens Falls Inc.**

Read "Cogen" instead of "Cagen" in this title.

Under condition 2 (c), read "2 093 700 000 cubic metres" instead of "2 093 700 cubic metres".

(vii) **Unigas Corporation**

Under condition 2, read "The quantity of gas..." instead of "Subject to condition 3, the quantity of gas...".

Attachment

Appendix VI
Certificate Conditions

1. The additional facilities shall be the property of and shall be operated by TransCanada.

2. (1) TransCanada shall cause the additional facilities to be designed, manufactured, located, constructed and installed in accordance with those specifications, drawings, and other information or data set forth in its application, or as otherwise adduced in evidence before the Board, except as varied in accordance with subsection (2) hereof.

   (2) TransCanada shall cause no variation to be made to the specifications, drawings or other information or data referred to in subsection (1) without the prior approval of the Board.

3. TransCanada shall implement or cause to be implemented all of the policies, practices, recommendations and procedures for the protection of the environment included in its application, its environmental reports filed as part of its application, its Pipeline Construction Specifications (1990), its Environmental Protection Practices Handbook (1986), its undertakings made to the Minister of Energy of Ontario (Ontario Pipeline Coordination Committee), or as otherwise adduced in evidence before the Board in the GH-5-89 proceeding.

4. Unless the Board otherwise directs, TransCanada shall, prior to the commencement of construction of any specific pipeline section referred to in this certificate, demonstrate to the Board's satisfaction that all necessary option or easement agreements have been executed by the landowners through whose property that loop section passes.

5. TransCanada shall, at least ten days prior to the commencement of construction, file with the Board the results of the heritage resource surveys referred to in the GH-5-89 proceeding, including any corresponding mitigative measures.

6. TransCanada shall, at least ten days prior to the commencement of construction, file with the Board a detailed construction schedule or schedules identifying major construction activities and shall notify the Board of any modifications to the schedule or schedules as they occur.

7. Unless the Board otherwise directs, TransCanada shall, prior to the commencement of construction, demonstrate to the Board's satisfaction that:

   (1) in respect of new firm export volumes, all necessary United States and Canadian federal regulatory approvals, including applicable long-term Canadian export authorizations have been granted; and

   (2) with respect to the transportation of new firm volumes on the TransCanada system:

      (a) transportation contracts have been executed;

      (b) all necessary United States and Canadian regulatory approvals have been granted in respect of any necessary downstream facilities or transportation services; and

(c) gas supply contracts have been executed.

8. Unless the Board otherwise directs, TransCanada shall, prior to the commencement of construction of any of the additional facilities, submit for Board approval:

(1) requirements tables in the same format as Tables 2, 3, and 5 of subtab 1 under tab "Requirements" of Exhibit B-1 from the GH-5-89 proceeding, showing the anticipated base case requirements and those requirements for which condition 7 has been satisfied; and

(2) flow schematics of the TransCanada system demonstrating that those approved facilities which are to be released for construction are necessary to transport the requirements referred to in subsection (1).

9. During construction, TransCanada shall file with the Board monthly construction progress and cost reports, providing a breakdown, by location and facility, of costs incurred during that month, the percentage completed of each activity and an update of projected costs to complete the project.

10. TransCanada shall, within six months of putting the additional facilities into service, file with the Board a report providing:

(1) a breakdown of the costs incurred in the construction of the additional facilities in the format used in Schedules 3 through 29 of subtab 10 under tab "Facilities" of Exhibit B-1 to the GH-5-89 proceeding, setting forth actual versus estimated costs, including reasons for significant differences from estimates; and

(2) the percentage of Canadian content realized in comparison with that estimated in Schedules 31 and 32 of Tab 10 under Tab "Facilities", of Exhibit B-1 to the GH-5-89 proceeding, including reasons for significant differences.

11. (1) TransCanada shall file with the Board a post-construction environmental report within six months of the date that the last leave to open is granted for the additional facilities.

(2) The post-construction environmental report referred to in subsection (1) shall set out the environmental issues that have arisen up to the date on which the report is filed and shall:

(a) indicate the issues resolved and those unresolved; and

(b) describe the measures TransCanada proposes to take in respect of the unresolved issues.

(3) TransCanada shall file with the Board, on or before the 31 December that follows each of the first two complete growing seasons after the post-construction environmental report referred to in subsection (2) is filed:

(a) a list of the environmental issues indicated as unresolved in the report and those that have arisen since the report was filed, if any; and

(b) a description of the measures TransCanada proposes to take in respect of any unresolved environmental issue.

12. Unless the Board otherwise directs prior to 31 December 1992, this certificate shall

expire on 31 December 1992 unless the construction and installation with respect to each of the additional facilities has commenced by that date.

National Energy Board

Reasons for Decision

In the Matter of

TransCanada PipeLines Limited

GH-5-89

April 1991

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Facilities, Gas Exports and
Section 71 Applications

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Recital and Appearances

IN THE MATTER OF the *National Energy Board Act* ("the Act") and the regulations made thereunder;

AND IN THE MATTER OF an application by TransCanada PipeLines Limited for a Certificate under Part III of the Act for certain proposed additional facilities for 1991 and 1992;

AND IN THE MATTER OF various associated applications for licences for the export of natural gas pursuant to Part VI of the Act;

AND IN THE MATTER OF applications made by various parties for orders pursuant to section 71 of the Act;

AND IN THE MATTER OF issues relating to toll methodology pursuant to Part IV of the Act and relating to economic feasibility matters;

AND IN THE MATTER OF Hearing Order GH-5-89.

HEARD at Ottawa, Ontario on 26, 27, 28, 29, 30 March, 2, 3, 4, 5, 6 April, 14, 15, 16, 17, 18, 28, 29, 30, 31 May, 1, 4, 5, 6, 7, 8, 11, 12, 13, 14, 15, 25, 26, 27, 28, 29 June, 3, 4, 5, 6, 9, 10, 11, 12, 30, 31 July, 1, 2, 3, 7, 8, 9, 10, 13, 14, 20, 21, 22, 23, 27, 28, 29, 30, 31 August, 4, 5, 6, 17, 18, 19, 20, 21, 24, 25, 26 September, 15, 18 October, 19, 20, 21, 26, 27, 28, 29 November and 10, 11, 12, 13 December 1990;

AND Calgary, Alberta on 23, 24, 25, 26, 27, 30 April and 1, 2, 3 May 1990.

BEFORE:

J.-G. Fredette	Presiding Member
A.B. Gilmour	Member
M.J. Musgrove	Member
R. Illing	Member
K.W. Vollman	Member

APPEARANCES:

R.B. Cohen N.D. Patterson J.T. Petrosoniak J.W.S. McOuat, Q.C.	TransCanada PipeLines Limited
F.M. Saville, Q.C.	Canadian Occidental Petroleum Limited
D.W. Rowbotham	Enserch Development Corporation, on behalf of Encogen Four Partners, L.P.
H.R. Ward	Esso Resources Canada Limited
S.H. Lockwood	FSC Resources Limited

D.G. Davies	Fulton Cogeneration Associates
K.F. Miller	Indeck Gas Supply Corporation
L.G. Keough N. Gretener	JMC Selkirk, Inc.
D.A. Holgate A.L. McLarty	Kamine Carthage Cogen Co. Inc. and Beta Carthage Inc. Kamine South Glens Falls Cogen Co. Inc. and Beta South Glens Falls Inc.
D.G. Hart, Q.C.	New England Power Company
D.C. Edie	Pawtucket Power Associates Limited Partnership by its agent Brymore Energy Limited
K.J. MacDonald J. Kowch M. Grant	ProGas Limited
D.G. Davies	Unigas Corporation
M.G. Samuel L.W. Sloane M.P. Stauft	Western Gas Marketing Limited
D. Goffin	Canadian Chemical Producers' Association
C.K. Yates D.A. Holgate	Canadian Petroleum Association
J.A. Snider	Independent Petroleum Association of Canada
M. Mason	Industrial Gas Consumers Association of Alberta
P.C.P. Thompson, Q.C.	Industrial Gas Users Association
J.A. Snider	AEC Oil and Gas Company, a division of Alberta Energy Company Limited
A.A. Fradsham N.W. Boutillier	Alberta Natural Gas Company Limited
L.E. Smith	Alberta Northeast Gas Export Project
A.A. Fradsham N.W. Boutillier	Alberta & Southern Gas Co. Ltd.
W.M. Moreland	Amoco Canada Petroleum Company Limited
T. Hughes	Altresco

J.H. Smellie C.W. Ulrich T.J. McCunn	CNG Transmission Corporation
L.G. Keough	Canadian Hunter Exploration Limited
S. Carscallen	CanStates Gas Marketing
R.J. Harrison	Champlain Pipeline Company
T. Brett	Commercial Union Energy Corporation
J.H. Farrell H.T. Soudek	Consumers' Gas Company Ltd., The
F.X. Berkemeier	Consumers Power Company
T. Brett	Direct Energy Marketing Limited
H.N.E. Hobbs	Foothills Pipe Lines Limited
R. Lassonde F. G. Hébert J.S. Bulger A.M. Bigué S. Struthers	Gaz Métropolitain, inc.
M.M. Petersen	General Chemical Canada Ltd.
D. Brett	ICG Utilities (Manitoba) Ltd.
J.H. Smellie D.K. Wilson	ICG Utilities (Ontario) Ltd
M.M. Peterson	ICI Canada Inc. (formerly C-I-L Inc.)
F.M. Lowther B.L. Webb	Iroquois Gas Transmission System
J.T. Horte	KannGaz Producers Limited
R. Daileader	L & J Energy Systems, Inc.
L.G. Keough N. Gretener	MASSPOWER Joint Venture
A.R. O'Brien P. Miller	Michigan Consolidated Gas Company
T. Brett	Natural Gas Pipeline Company of America
J.H. Farrell H.T. Soudek	Niagara Gas Transmission Limited

J.J. Marshall	Norcen Energy Resources Limited
J. Hopwood, Q.C.	NOVA Corporation of Alberta
D.A. Dawson G. Giesbrecht	Pan-Alberta Gas Limited
A.S. Hollingworth	PanCanadian Petroleum Limited
W. Fruehauf	PPG Canada Limited
S.W. Widger	Rochester Gas and Electric Corporation
H. Huber	Saskatchewan Energy Corporation
D.G. Davies	St. Clair Pipelines Limited
B.J. McHugh	Southcoast Energy Ltd.
N.J. Schultz J. Burke-Robertson B. Swick-Martin	Tennessee Gas Pipeline Company
J.F. Weiler	Texas Eastern Transmission Corporation
W.J. Burke-Robertson	Transcontinental Gas Pipe Line Corporation
G.K. Cameron	Union Gas Limited
A.M. Bigué S. Struthers	Vermont Gas Systems, Inc.
N.J. Schultz J. Burke-Robertson B. Swick-Martin S. Halbach	Viking Gas Transmission Company
P.G. Griffin	Westcoast Energy Inc.
A.M. Mueser	GASP Coalition
L.L. Manning	Alberta Petroleum Marketing Commission
V.J. Black	Minister of Energy for Ontario
J. Giroux G.A. Trudel J. Robitaille	Procureur général du Québec

D. Burnett	Province of New Brunswick
L. Meagher D. Bursey M.A. Fowke	National Energy Board

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Tables

Figures

Appendices

Abbreviations

AAMP	Average Alberta Market Price
ABP	adjusted base price
ACAPG	average cost of all purchased gas
ACQ	annual contract quantity
Act	*National Energy Board Act*
AERCB	Alberta Energy Resources Conservation Board
Algonquin	Algonquin Gas Transmission Company
Altex	Altex Resources Ltd.
American Brass	American Brass Company, L.P.
ANE	Alberta Northeast Gas Export Project
ANR	ANR Pipeline Company
APMC	Alberta Petroleum Marketing Commission
Bay State	Bay State Gas Company
Bcf	billion cubic feet
BEC	Boston Edison Company
BGC	Boston Gas Company
Board, NEB	National Energy Board
BP Resources	BP Resources Canada Limited
Brymore	Brymore Energy Limited
Can Oxy	Canadian Occidental Petroleum Limited
CEC	Commonwealth Edison Company
CNG	CNG Transmission Corporation
Colfax	Colfax, Inc.
Columbia	Columbia Gas Development of Canada Ltd.
Con Ed	Consolidated Edison Company of New York, Inc.
Consumers'	Consumers' Gas Company Ltd., The

CPA	Canadian Petroleum Association
DCQ	daily contract quantity
Devnic	Devnic Energy Inc.
DOE/FE	(U.S.) Department of Energy/Office of Fossil Energy
DuPont	E.I. DuPont de Nemours and Company, Inc.
EDC	EDC Four, Inc.
EIA	Export Impact Assessment
EIL	Environmental Issues List
Elizabethtown	Elizabethtown Gas Company
Empire	Empire State Pipeline
Encogen	Encogen Four Partners, L.P.
Enserch	Enserch Development Corporation
Esso	Esso Resources Canada Limited
Falcon Gas	Falcon Seaboard Gas Company
Falcon Resources	Falcon Seaboard Resources Inc.
FAQ	facilities application queue
FERC	(U.S.) Federal Energy Regulatory Commission
Foster	Foster Associates, Inc.
FS	firm service
FSC	FSC Resources Limited
FST	firm service tendered
Fulton	Fulton Cogeneration Associates
GRI	Gas Research Institute
G.E.	General Electric Company
GH-1-89	Hearing Order GH-1-89 in respect of TransCanada's application for 1990 facilities and various applications for natural gas export licences

GH-2-87	Hearing Order GH-2-87 in respect of TransCanada's applications for 1989 and 1990 facilities and approval of toll methodology and related tariff matters
GH-6-89	Hearing Order GH-6-89 in respect of Esso Resources Canada Limited application for a change, alteration or variation of Licence GL-82 and CanStates Gas Marketing and Transco Energy Marketing Company, FSC Resources Limited, Ramarro Resources Inc., Vector Energy Inc., Western Gas Marketing Limited applications for licences to export natural gas
GH-7-88	Hearing Order GH-7-88 in respect of ProGas Limited application for a change, alteration or variation of natural gas export licence GL-81 and Western Gas Marketing Limited application for a change, alteration or variation of natural gas export Licence GL-90
GJ	gigajoule(s)
GMi	Gaz Métropolitain, inc.
Granite State	Granite State Gas Transmission Inc.
Great Lakes	Great Lakes Gas Transmission Company
ICC	incentive commodity charge
ICG (Manitoba)	ICG Utilities (Manitoba) Ltd. (name changed to Centra Gas Manitoba Inc.)
ICG (Ontario)	ICG Utilities (Ontario) Ltd (name changed to Centra Gas Ontario Inc.)
IGTS	Iroquois Gas Transmission System
IGUA	Industrial Gas Users Association
Indeck	Indeck Gas Supply Corporation
Indeck Corinth	Indeck Gas Supply Corporation - Indeck Corinth
Indeck-Ilion	Indeck Gas Supply Corporation - Indeck-Ilion
Indeck Services Corinth	Indeck Energy Services of Corinth, Inc.
Indeck Services Ilion	Indeck Energy Services of Ilion, Inc.
International Paper	International Paper Company
Inverness	Inverness Petroleum Ltd.
IPAC	Independent Petroleum Association of Canada, The
James River II	James River II, Inc.
JCP&L	Jersey Central Power and Light
Jensen or JAI	Jensen Associates, Inc.

JMAI	J. Makowski Associates, Inc.
Kamine Carthage	Kamine Carthage Cogen Co., Inc. and Beta Carthage Inc.
Kamine South Glens Falls	Kamine South Glens Falls Cogen Co., Inc. and Beta South Glens Falls Inc.
km	kilometre(s)
kPa	kilopascals
kW.h	kilowatt-hour(s)
LDC(s)	local distribution company(ies)
LICLP	Long Island Cogeneration Limited Partnership
LIF	limited interruptible firm
LILCO	Long Island Lighting Company
LNG	liquefied natural gas
LRAC	long-run average cost
m	metre(s)
m^3	cubic metres
m^3/d	cubic metres per day
MAQ	minimum annual quantity
Mark	Mark Resources Inc.
MASSPOWER	MASSPOWER Joint Venture
MAQ	minimum annual quantity
MCQ	monthly contract quantity
MDQ	maximum daily quantity
MFNC	MacNamara Field Naturalists Club
mm	millimetres
MMBtu	million British thermal units
MMcf	million cubic feet
MMcfd	million cubic feet per day
MMWEC	Massachusetts Municipal Wholesale Electric Company

MNR	Ministry of Natural Resources (Ontario)
Monsanto	Monsanto Company
MOE	Ministry of the Environment (Ontario)
MW	megawatts
MW.h	megawatt-hour(s)
National Distribution	National Fuel Gas Distribution Corporation
National Fuel	National Fuel Gas Supply Corporation
NEES	New England Electric System
NEP	New England Power Company
NEPEX	New England Power Exchange
NEPOOL	New England Electric Power Pool
Nestle	Nestle Food Corporation
Niagara Mohawk	Niagara Mohawk Power Corporation
NIPS	Niagara Import Point System Projects
NorCon	Northern Consolidated Power, Inc.
Northern Utilities	Northern Utilities Inc.
Northstar	Northstar Energy Corporation
NOVA	NOVA Corporation of Alberta
NU	Northeast Utilities Service Company
NUG	non-utility generator
NYSPSC	New York State Public Service Commission
Oakwood	Oakwood Petroleums Limited
OMV	OMV (Canada) Ltd.
Ontario	Ministry of Energy for Ontario
OPCC	Ontario Pipeline Coordination Committee
Opinac	Opinac Exploration Limited
Orchard Gas	Orchard Gas Corporation

PanCanadian	PanCanadian Petroleum Limited
Paramount	Paramount Resources Ltd.
Part VI Regulations	*National Energy Board Part VI Regulations*
Pawtucket	Pawtucket Power Associates Limited Partnership
PJ	petajoule(s)
PPBR	Plans, Profiles and Books of Reference
PreCambrian	PreCambrian Shield Resources Limited
ProGas	ProGas Limited
PURPA	(U.S.) Public Utility Regulatory Policies Act of 1978
QF	qualifying cogeneration facility
RAC	refiners acquisition cost
RDP	Real Domestic Product
Renaissance	Renaissance Energy Ltd.
RG&E	Rochester Gas and Electric Corporation
RH-3-89	Hearing Order RH-3-89 in respect of TransCanada's application for new tolls for 1990
RQ	requirements service
RR/P	reserves-to-production ratio
Saskatchewan	Saskatchewan Department of Energy and Mines
SBP	summer base price
Sceptre	Sceptre Resources Limited
Selkirk	JMC Selkirk, Inc.
Sproule	Sproule Associates Limited
Star	Star Oil and Gas Ltd.
Tcf	trillion cubic feet
Tennessee	Tennessee Gas Pipeline Company
Tetco	Texas Eastern Transmission Corporation
Texas Gas	Texas Gas Transmission Company

Top Gas	Take-or-Pay Gas
TransCanada	TransCanada PipeLines Limited
Transco	Transcontinental Gas Pipe Line Corporation
TransGas	TransGas Limited
Trilogy	Trilogy Resource Corporation
Triton	Triton Canada Resources Limited
Turner	Turner Power Group, Inc.
U.S.	United States of America
Unigas	Unigas Corporation
Union	Union Gas Limited
Universal	Universal Exploration Ltd.
Valley Gas	Valley Gas Company
WBP	winter base price
WCSB	Western Canadian Sedimentary Basin
Welch	Welch Foods Inc., a cooperative
Westcoast	Westcoast Energy Inc.
WGML	Western Gas Marketing Limited
WMECO	Western Massachusetts Electric Company

Overview

(NOTE: This overview is provided solely for the convenience of the reader and does not constitute part of this Decision or the Reasons, to which readers are referred for the detailed text and tables.)

The Facilities Application

By application dated 29 June 1989, as amended 15 December 1989, TransCanada PipeLines Limited ("TransCanada") applied for new facilities to increase deliveries to its domestic markets in eastern Canada and to export markets in the United States.

The proposed expansion would enable TransCanada to:

- meet its projected sales and transportation requirements for the 1991/92 and 1992/93 contract years (see Table 20-6), including new firm service contracts and changes in load factor for some existing customers;

- restore capability that would be lost due to the retirement of compressor units; and

- provide a minimum delivery pressure of 9 930 kPa at Iroquois, Ontario.

The proposed facilities consist of 1 590 kilometres of pipeline, the installation of 21 new compressor units and two new compressor stations. The total cost of the proposed facilities was originally estimated to be $2 573 million. This estimate was reduced to $2 408 million during the course of the proceedings. TransCanada's 1990 approved rate base is $3.0 billion on a gross plant of $4.3 billion. TransCanada estimated that the proposed facilities would result in an increase in the Eastern Zone toll of approximately $0.09/gigajoule, using the rolled-in tolling methodology, compared to tolls without the expansion.

Details of the facilities addressed in this final phase of the proceedings, and their estimated cost, are provided in Table 22-1. A map indicating the location of these facilities appears as Figure 22.1.

Partial Facilities Certificate Application

On 31 August 1990, TransCanada requested that the National Energy Board ("the Board") consider issuing an early decision on a portion of the applied-for facilities to allow for winter construction to ensure November 1991 service for TransCanada's most assured requirements. On 3 October 1990, TransCanada submitted its evidence in support of this request to construct 396 km of system-wide pipeline looping and relocate two portable compressor units at a cost of $546 million. The facilities would provide 2 920 $10^3 m^3$/d (103 MMcfd) of firm service transportation required by specific domestic shippers and 1 470 $10^3 m^3$/d (52 MMcfd) of advance capacity for 1 November 1991. The application was heard by the Board on 15 and 18 October 1990 and granted on 15 November 1990. Detailed information regarding this portion of the hearing may be found in Volume 2 of the GH-5-89 Reasons for Decision.

TransCanada had also received in June 1990 Order XG-5-90 allowing the installation of three compressors related to the 1991/1992 expansion.

Export Applications

The Board considered in the hearing fifteen applications made pursuant to Part VI of the *National Energy Board Act* ("the Act") for gas exports at existing delivery points at Emerson and Niagara Falls as well as at proposed new delivery points at Chippawa and Iroquois, Ontario. The export applicants and delivery volumes associated with each export point are shown in Table 2-1.

Twelve of these applications were filed in support of TransCanada's facilities application, as detailed in Table 20-6.

Section 71 Applications

Applications were filed by Indeck Gas Supply Corporation ("Indeck") in respect of its Ilion project, Rochester Gas & Electric Corporation ("RG&E"), Falcon Seaboard Resources Inc., The Consumers' Gas Company Ltd. and Union Gas Limited, pursuant to section 71 of the Act, for orders requiring TransCanada to receive, transport and deliver natural gas offered by the applicants and to provide adequate and suitable facilities to do so. Though all five applications were set down for consideration at the hearing, only the Indeck and RG&E applications were heard, the others having been withdrawn.

The Hearing

A public hearing on the applications began in Ottawa on 26 March 1990. The portion of the hearing relating to economic feasibility and Part IV matters was conducted in Ottawa over fifty-nine days from 28 May 1990 to 26 September 1990. The main issues considered in this phase of the hearing were the appropriate toll treatment of the capital and operating costs of the proposed facilities, the appropriate toll treatment of fixed costs associated with the proposed facilities should they be under-utilized in the future, the continued appropriateness of the renewal rights policy and the means by which the economic feasibility of the proposed facilities could be determined. The Board released its findings on this phase of the proceedings on 8 November 1990 in Volume 1 of the GH-5-89 Reasons for Decision.

The remaining evidence on the facilities application, the export applications, section 71 applications and consideration of the toll treatment of cost overruns were heard in the final phase of the GH-5-89 proceedings between 19 November and 13 December 1990.

Highlights of the Board's Decision

Part VI Matters

The Board granted gas export licences to the fifteen parties that filed Part VI applications. In the case of Brymore Energy Ltd. as agent for Pawtucket Power Associates Limited Partnership ("Pawtucket"), the Board was not satisfied that the evidence with regard to supply and commercial necessity was adequate to support the issuance of a 20-year export licence as applied-for and, therefore, issued a licence to Pawtucket for a 15-year term. The licence issued to FSC Resources Limited ("FSC") includes a condition requiring that, prior to the commencement of exports, FSC shall not, without Board approval, replace either its gas supply or its market from that described during the course of the GH-5-89 proceedings.

Part III Matters

Supply

The Board was satisfied that there would be adequate natural gas supply to ensure sufficient utilization of the TransCanada system, including the proposed expansion. The Board recognized that production from sources other than the Western Canada Sedimentary Basin might be required in later years to meet projected demand.

Requirements

The Board found TransCanada's assessment of long-term domestic and export requirements to be reasonable for the purposes of assessing the facilities requirements for the 1991/92 and 1992/93 contract years. The Board also determined that there was a long-term market for natural gas in the U.S. Northeast and that there is a role for Canadian gas in that region.

Contractual Arrangements and Risk Allocation

The Board was not persuaded that it should attempt to determine in advance the toll treatment for future unrecovered demand charges. In that regard, the Board found that, in the event of any demand charges being unrecovered in the future as a result of the failure of a particular financial assurance agreement, the prudency of that agreement would be examined in a future tolls proceeding. Furthermore, the Board was not prepared to impose a condition in any certificate to be issued that would require an amendment to the gas sales contracts eliminating the potential for a claim of force majeure stemming from state regulatory action.

Facilities

The Board found that the applied-for facilities represent an appropriate design for an expansion of the TransCanada system and would be required to meet the forecast market requirements. The Board encouraged TransCanada to purchase and install compressor units in a timely manner, and to achieve a facilities build-up which is balanced as much as possible throughout the expansion period.

Land Use and Environmental Matters

The Board found that the proposed facilities would create only minimal environmental impacts of a local and temporary nature, if the proposed environmental protection measures are implemented.

The Board granted TransCanada's request to exempt the new facilities, all of which would be installed along the existing pipeline infrastructure, from the requirements of detailed route proceedings. However, in order to protect the interests of the owners of the lands proposed to be acquired by TransCanada, the exemption would be conditional on all necessary options or easement agreements being executed by the affected landowners prior to the commencement of construction.

Economic Feasibility

The Board evaluated the economic feasibility of the proposed expansion using the factors enumerated in the Reasons for Decision in respect of the first phase of these proceedings. Based on its findings in respect of these factors, the Board was satisfied that the proposed expansion is economically feasible and that the facilities would be reasonably utilized over their economic life.

Part IV Matters

Section 71 Applications

The Board found that Indeck and RG&E had both failed to meet the deadline established by TransCanada for filing project status and evidentiary support documentation. Furthermore, the Board was not persuaded that the export projects of Indeck and RG&E would be jeopardized if they were denied the relief sought. Accordingly, the Board denied the applications of Indeck and RG&E filed pursuant to subsections 71(2) and 71(3) of the Act.

Toll Treatment of Cost Overruns

The Board found that the existing procedure for treatment of variances between forecast and actual capital costs provides for sufficient control over TransCanada's capital expenditures.

Retirement of Compressors

The Board found the compressor retirements proposed by TransCanada to be ordinary retirements within the meaning of subsection 39(1) of the Gas Pipeline Uniform Accounting Regulations.

Introduction

1.1 Sequence of Events

Following the issuance of Hearing Order GH-5-89, in which the National Energy Board ("the Board" or "NEB") indicated that it would hear the TransCanada PipeLines Limited ("TransCanada") facilities application, associated gas export licence applications and applications made pursuant to section 71 of the *National Energy Board Act* ("the Act"), a pre-hearing conference was held on 21 November 1989 to hear parties' views on whether the preliminary List of Issues contained in GH-5-89 was complete. At these preliminary proceedings, the Industrial Gas Users Association ("IGUA") and others argued that the Board should consider the issue of alternative toll methodologies.

On 1 December 1989, the Board issued its decisions regarding matters raised at the pre-hearing conference. One of its decisions was to reject the suggestion that toll methodology should be examined in the GH-5-89 hearing. IGUA and The Consumers' Gas Company Ltd. ("Consumers) thereupon applied to the Federal Court for an order directing the Board to consider the issue of tolling methodology in the GH-5-89 proceedings. The motions were granted in a decision dated 12 February 1990. Consequently, the Board amended the GH-5-89 List of Issues to include a consideration of the appropriate toll treatment of the costs of the proposed facilities.

The GH-5-89 hearing began in Ottawa, Ontario on 26 March 1990 with the consideration of the Part III application. After sitting for two weeks the hearing moved to Calgary, Alberta on 23 April for an additional two weeks of hearings during which approximately half of the export applications were heard. Soon after reconvening in Ottawa on 15 May, the Board heard motions by various parties to restructure the hearing. On 17 May the Board decided to suspend the hearing until 23 May (subsequently changed to 28 May) at which time it would reconvene to hear all parties' evidence and arguments on tolling methodology and economic feasibility. The Board indicated that it would render a decision on these matters before proceeding to hear the remaining Part III and Part VI matters before it. The issue of the appropriate toll treatment of variances between forecast and actual construction costs of the proposed facilities was to have been examined in this phase of the proceedings, however, this matter was deferred to a later date due to the unavailability of a witness.

In issuing its decision on 17 May, the Board reaffirmed its position that the tolling methodology for previously certificated facilities was not an issue in the GH-5-89 proceedings but that IGUA would be allowed to present evidence relating to the tolling of previously certificated facilities for comparative purposes.

IGUA again applied to the Federal Court arguing that the Board had interpreted the 12 February 1990 decision too narrowly and requested a direction that the issue of toll methodology be considered not only with respect to traffic on the proposed facilities but with respect to traffic on previously certificated facilities as well.

The Court denied IGUA's request in a decision delivered on 17 August 1990. The hearing continued and final argument on the Part IV and economic feasibility phase of the hearing was heard from 17 to 28 September 1990. The Board subsequently released Volume 1 of its GH-5-89 Reasons for Decision on 8 November 1990 wherein it decided, among other matters, that the cost of all facilities certificated as a result of the GH-5-89 proceedings would be rolled into TransCanada's rate base for tolling purposes. It also stated that it would make a determination of the economic feasibility of the proposed facilities by having regard to evidence on all relevant factors which impact on the likelihood of the facilities being used at a reasonable level over their economic life and of the likelihood of the demand charges being paid.

On 29 May 1989, in order to ensure timely service for TransCanada's most assured requirements for the 1991/92 contract year, the Board approved TransCanada's request, pursuant to section 58 of the Act, for installation of three compressor units associated with the GH-5-89 expansion.

Due to the complexity of the issues being considered in the GH-5-89 proceedings, the hearing was considerably more protracted than originally expected. On 31 August 1990, TransCanada requested that the Board consider a partial facilities application which would allow for winter construction to satisfy its most assured requirements and also some advance capacity by 1 November 1991. On 3 October 1990, TransCanada submitted evidence in support of its request to construct 396 km of system-wide pipeline looping and relocate two portable compressor units at a cost of $546 million. The Board heard evidence and argument on this application on 15 and 18 October 1990 and subsequently granted TransCanada's request in Volume 2 of its GH-5-89 Reasons for Decision issued on 15 November 1990.

During the period between the filing of TransCanada's amended application and the release of this final volume of the Reasons for Decision, the Board issued various other orders for the construction and installation of certain facilities associated with the GH-5-89 expansion. A summary of these orders and the associated proposed facilities is provided in Appendix V.

The remaining evidence on the facilities application, the export applications, section 71 applications and consideration of the toll treatment of cost overruns was heard in the final phase of the GH-5-89 proceedings between 19 November and 13 December 1990.

1.2 Summary of Facilities, Export Licences, and Section 71 Applications

Facilities Application

By application dated 29 June 1989, as amended 15 December 1989, TransCanada applied for new facilities to increase deliveries to its domestic markets in eastern Canada and to export markets in the United States.

The proposed expansion would enable TransCanada to:

- meet its projected sales and transportation requirements for the 1991/92 and 1992/93 contract years (see Table 20-6), including new firm service contracts and changes in load factor for some existing customers;
- restore capability that would be lost due to the retirement of compressor units; and
- provide a delivery pressure of 9 930 kPa at Iroquois, Ontario.

The total proposed facilities consist of 1 590 km of pipeline, the installation of 21 new compressor units and two new compressor stations. The total cost of the proposed facilities was originally estimated to be $2 573 million; this figure was subsequently reduced to an estimated $2 408 million. TransCanada's 1990 approved rate base is $3.0 billion on a gross plant of $4.3 billion. TransCanada estimated that, using the rolled-in tolling methodology, the proposed facilities would result in an increase in the Eastern Zone toll of approximately $0.09/GJ relative to tolls without the expansion.

As indicated above, certain facilities associated with the GH-5-89 expansion have been previously approved by the Board. The outstanding facilities addressed by this volume of the decision are detailed in Table 22-1. These facilities represent 1 190 km of pipeline looping and 17 compressor units at a cost of $1.835 billion. A map indicating the location of these facilities appears as Figure 22.1.

Export Applications

The Board considered in the hearing fifteen applications made pursuant to Part VI of the Act for gas exports at existing delivery points at Emerson, Manitoba and Niagara Falls, Ontario as well as at proposed delivery points at Chippawa and Iroquois, Ontario. The export applicants and delivery volumes associated with each export point are shown in Table 2-1.

Twelve of these applications were filed in support of TransCanada's facilities application, as detailed in Table 20-6.

Section 71 Applications

Applications were filed by Indeck Gas Supply Corporation ("Indeck") in respect of its Ilion project, Rochester Gas & Electric Corporation ("RG&E"), Falcon Seaboard Resources Inc.

("Falcon Resources"), Consumers' and Union Gas Limited ("Union"), pursuant to section 71 of the Act, for orders requiring TransCanada to receive, transport and deliver natural gas offered by the applicants and to provide adequate and suitable facilities to do so. Though all five applications were set down for consideration at the hearing, only the Indeck and RG&E applications were heard, the others having been withdrawn.

1.3 Environmental Screening

The Board conducted an environmental screening in accordance with the *Environmental Assessment and Review Process Guidelines Order* to determine whether, and if so, the extent to which, there might be any potential adverse environmental effects arising from the applications for facilities, export licences and orders pursuant to section 71 of the Act considered in the GH-5-89 proceedings. As a result of the screening, the Board found that environmental effects and any social effects directly related to environmental effects of the proposals would be insignificant or mitigable with known technology.

1.4 Structure of Reasons for Decision

In the GH-5-89 hearing, the Board dealt with the facilities application by TransCanada under Part III of the Act and with the 15 export applications under Part VI of the Act. Combining the applications in a single hearing permitted a more efficient process in that evidence common to both decisions needed to be examined only once. In particular, the Board took account of information submitted by the export applicants to aid in the assessment of the supply and markets which support the facilities application, as well as to determine the public interest of each export application.

Notwithstanding that common information was used in support of both the Part III and Part VI applications, the Board's decisions on these applications were arrived at independently. The independence of the decisions is consistent with the different criteria which the Board uses in assessing requests for certificates and those for export licences.

In this regard, the consolidated process followed by the Board in GH-5-89 did not differ in substance from the process which would have been followed had the facilities application and export applications been heard separately. Indeed, in this proceeding not all of the export shipments supporting the facilities application were subject to review pursuant to Part VI of the Act since export licences had, in some cases, already been obtained. However, even in those instances, a review and update of previously submitted supply and market evidence was undertaken because of its relevance to any Part III finding. As well, a positive finding on a Part VI application need not bear on whether the Board will find the facilities to be in the public convenience and necessity or whether an order under subsection 71(2) or 71(3) of the Act should be issued.

The Board's review and decisions relating to the applications considered in the GH-5-89 proceedings and contained in Volume III of these Reasons are structured as follows:

	Chapter(s)
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Part III Matters	
Summary of TransCanada's Application	18
Supply	19
Requirements	20
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Land Use and Environment	23
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Part IV Matters	
Section 71 Applications	26
Toll Treatment of Cost Overruns	27
Accounting Treatment for Retirement of Compressors	28

PART VI MATTERS

Chapter 2

Gas Export Licence Applications

2.1 The Applications

During the GH-5-89 proceeding, the Board examined 15 applications for gas export licences. The applications were filed by the following companies:

1. Brymore Energy Ltd. ("Brymore") as agent for Pawtucket Power Associates Limited Partnership ("Pawtucket")
2. Canadian Occidental Petroleum Limited ("Can Oxy")
3. Encogen Four Partners L.P. ("Encogen")
4. Esso Resources Canada Limited ("Esso")
5. FSC Resources Limited ("FSC")
6. Fulton Cogeneration Associates ("Fulton")
7. Indeck Gas Supply Corporation/Indeck Corinth ("Indeck Corinth")
8. Indeck Gas Supply Corporation/Indeck-Ilion ("Indeck-Ilion")
9. JMC Selkirk Inc. ("Selkirk")
10. Kamine Carthage Cogen Co., Inc. and Beta Carthage Inc. ("Kamine Carthage")
11. Kamine South Glens Falls Cogen Co., Inc. and Beta South Glens Falls Inc. ("Kamine South Glens Falls")
12. New England Power Company ("NEP")
13. ProGas Limited ("ProGas")
14. Unigas Corporation ("Unigas")
15. Western Gas Marketing Limited ("WGML")

Table 2-1 provides a summary of each of the export licence applications reviewed during the GH-5-89 proceeding.

2.2 Market-Based Procedure

The Board, in considering an export application, must take into account section 118 of the Act which requires that the Board have regard to all considerations that appear to it to be relevant and in particular, that the Board satisfy itself that the quantity of gas to be exported does not exceed the surplus remaining after due allowance has been made for reasonably foreseeable Canadian requirements, taking account of trends in discovery.

To comply with the requirements of section 118 of the Act, the Board utilizes its Market-Based Procedure. The discussion of the Board's Market-Based Procedure that follows is general in nature and applies to each of the export applications heard in the GH-5-89 proceeding.

The Market-Based Procedure provides that the Board consider:

- complaints, if any, under the complaints procedure;
- an export impact assessment ("EIA"); and
- any other factors that the Board considers relevant to its determination of the public interest.

2.2.1 Complaints Procedure

When an application for an export licence is filed with the Board, interested parties have an opportunity to examine the various elements of the proposal. It is open to Canadian users of natural gas to come forward and object to the export on the grounds that they cannot obtain additional supplies of gas under contract on terms and conditions, including price, similar to those in the export proposal.

Table 2-1

Summary of Applied-for Licences

GH-5-89

				Maximum Quantities Applied-for		
Applicant	**Buyer (Type of market)**	**Term**	**Export Point**	**Daily $10^3 m^3$ (MMcf)**	**Annual $10^6 m^3$ (Bcf)**	**Term $10^6 m^3$ (Bcf)**
1. Pawtucket	Pawtucket (cogeneration plant)	1 Nov. 1991 to 31 Oct. 2011	Iroquois, Ontario	362.5 (12.8)	132.4 (4.7)	2 648.0 (93.5)
2. Can Oxy	LICLP (cogeneration plant)	1 Nov. 1991 to 31 Oct. 2006	Niagara Falls, Ontario	433.4 (15.3)	158.2 (5.6)	2 373.0 (83.8)
3. Encogen	Encogen (cogeneration plant)	1 Nov. 1991 to 31 Oct. 2006	Chippawa, Ontario	424.9 (15.0)	155.1 (5.5)	2 326.6 (82.1)
4. Esso	BGC (system system)	1 Nov. 1991 to 31 Oct. 2006	Iroquois, Ontario	991.5 (35.0)	362.0 (12.8)	5 432.0 (191.8)
5. FSC	FSC (cogeneration plant)	1 Nov. 1991 to 31 Oct. 2006	Niagara Falls, Ontario	453.0 (16.0)	165.3 (5.8)	2 480.2 (87.6)
6. Fulton	Fulton (cogeneration plant)	1 Nov. 1991 to 31 Oct. 2005	Chippawa, Ontario	326.2 (11.5)	119.0 (4.2)	
				160.0 (5.7)	58.4 (2.1)	
						1 424.0 (50.3)
7. Indeck Corinth	Indeck Services Corinth (cogeneration plant)	1 Nov. 1991 to 31 Oct. 2006	Chippawa, Ontario	459.0 (16.3)	168.0 (6.0)	2 439.0 (86.6)

Table 2-1 (cont'd)

Applicant	Buyer (Type of market)	Term	Export Point	Maximum Quantities Applied-for: Daily $10^3 m^3$ (MMcf)	Annual $10^6 m^3$ (Bcf)	Term $10^6 m^3$ (Bcf)
8. Indeck-Ilion	Indeck Services Ilion (cogeneration plant)	1 Nov. 1991 to 31 Oct. 2006	Chippawa, Ontario	210.0 (7.5)	73.0 (2.6)	852.0 (30.2)
9. Selkirk	Selkirk (cogeneration plant)	1 Nov. 1991 to 31 April 2007	Iroquois, Ontario	651.5 (23.0)	237.8 (8.4)	3 685.9 (130.1)
10. Kamine Carthage	Kamine/Besicorp Carthage L.P. (cogeneration plant)	1 Nov. 1991 to 31 Oct. 2006	Chippawa, Ontario	402.2 (14.2)	139.5 (4.9)	2 093.7 (74.0)
11. Kamine South Glens Falls	Kamine/Besicorp South Glens Falls L.P. (cogeneration plant)	1 Nov. 1991 to 31 Oct. 2006	Emerson, Manitoba	402.2 (14.2)	139.5 (4.9)	2 093.7 (74.0)
12. NEP	NEP (electricity generation)	1 Nov. 1991 to 31 Oct. 2006	Iroquois, Ontario	1 700.0 (60.0)	621.0 (21.9)	9 308.0 (328.5)
13. ProGas	MASSPOWER (cogeneration plant)	1 Nov. 1991 to 31 Oct. 2009	Iroquois, Ontario	708.2 (25.0)	258.2 (9.1)	4 800.4 (170.0)
14. Unigas	RG&E (system supply)	10 years after commencement of firm deliveries	Chippawa, Ontario	453.2 (16.0)	165.5 (5.8)	1 654.2 (58.7)
15. WGML	Elizabethtown (system supply)	15 years after commencement of firm deliveries	Niagara Falls, Ontario	283.0 (10.0)	103.7 (3.7)	1 552.0 (54.8)

There were no complaints made with respect to the applications for export licences in the GH-5-89 proceeding.

2.2.2 Export Impact Assessment

The purpose of the EIA is to assist the Board in determining whether a proposed export is likely to cause Canadians difficulty in meeting their future energy requirements at fair market prices. When the Market-Based Procedure was first introduced, each export applicant was required to file an EIA assessing the impact of the proposed export on domestic natural gas supply, demand, and prices, and on the ability of Canadian energy markets to adjust to these changes without difficulty.

Pursuant to a review of EIA filing requirements conducted in the fall of 1989, the Board decided that, while it would retain the EIA as part of its Market-Based Procedure, it would conduct its own non-project-specific assessment. Applicants now have the option of using the Board's analysis or of preparing and submitting their own analysis as a basis for arguing whether the proposed exports would result in adjustment difficulties in Canadian energy markets.

Accordingly, each applicant in the GH-5-89 proceeding advised the Board and interested parties whether it intended to rely on the Board's most recent EIA or to submit its own EIA.

The following companies adopted the Board's EIA:

- Encogen
- FSC
- Fulton
- Indeck Corinth
- Indeck-Ilion
- Selkirk
- Kamine Carthage
- Kamine South Glens Falls
- ProGas
- Unigas
- WGML

The following companies submitted their own EIA:

- Pawtucket
- Can Oxy
- Esso
- NEP

Those companies submitting their own EIA argued that their individual export volumes were too small relative to overall Canadian demand and supply to result in any noticeable impact on natural gas markets. The Board concurs with these companies' analyses of the impact of their proposed exports on Canadian natural gas markets. However, the Board has examined the total 3 059 10^6m^3 (108 Bcf) per year applied for pursuant to Part VI in the GH-5-89 proceedings, and has found that, in aggregate, the volumes expected to flow fall within the range tested in the Board's most recent EIA (Reasons for Decision, Proposed Amendment to Export Impact Assessment Filing Requirements, November 1989).

In this regard the Board believes that the applied-for export volumes would have little impact on the production, consumption, and price of gas in Canada, and that Canadian energy users would not experience difficulty in meeting their future energy requirements as a result of the proposed export. The Board is also of the view that Canadian buyers of natural gas will not have significant problems adjusting to market forces that will result from approval of these exports.

2.2.3 Other Factors Relevant to the Public Interest

In addition to using the complaints procedure and the EIA to ascertain whether gas proposed to be exported is surplus, the Board continues, as required by section 118 of the Act, to have regard to all other factors it considers relevant in determining whether a proposed export is in the public interest.

In general, these factors can be placed into two categories: a) gas supply and, b) market and commercial arrangements and regulatory status. This listing of factors the Board may regard as relevant is illustrative rather than exhaustive, but the Board relies heavily on information filed by export licence applicants in accordance with the *National Energy Board Part VI Regulations* ("Part VI Regulations"). This information is used to assess whether an export proposal is in the public interest, and the onus is on the applicant to ensure that the filed material is such as to

persuade the Board that its project has substance and is at a sufficiently advanced stage of completion to warrant the issuance of a licence.

2.2.3.1 Gas Supply

The Board conducts a review of the applicants' gas supply arrangements to assist it in determining whether the proposed exports are in the public interest. In its assessment of gas supply, the Board examines the contractual arrangements pertaining to supply, the adequacy of both reserves and productive capacity to support the applied-for exports and the status of provincial removal authorizations.

A description of the Board's approach to supply analysis is contained in Appendix II of these Reasons.

2.2.3.2 Market and Commercial Arrangements and Regulatory Status

The Board conducts a review of the market and commercial arrangements and regulatory status underpinning projects to assist it in determining whether the proposed exports are in the public interest.

In the GH-5-89 proceedings the end-use markets were of three types; sales to local distribution companies ("LDCs"), sales to cogeneration facilities, and sales to an electrical utility for generation of electricity. The Board's and intervenors' review of these market types in the proceedings included the following for each market type:

- for exports to LDCs for system supply it included consideration of the LDCs' current and projected requirements and overall supply portfolio with a view to determining the need for and the role of the Canadian gas supply within that portfolio;

- for exports to a cogeneration facility, defined as a facility that produces electricity and thermal energy for use in commercial or industrial operations, an examination of the contractual chain, from the gas sales contract to the power and thermal sales contracts, was conducted. In this regard parties looked to the status of project financing, construction schedules, and qualifying cogeneration facility ("QF") certification. (The criteria for QF certification are described in Appendix III of these Reasons for Decision); and

- the examination of an export to supply gas to an electric utility's own generating facilities, either thermal generating plants and/or combined-cycle generation facilities, included a review of that utility's current and future requirements for electricity, its existing contractual commitments for power purchases, its current and projected generating capability and the electric utility's generating fuel mix and prices.

Regardless of the type of end-use market, the review included consideration, amongst other items, of the load factor at which the proposed export is expected to flow and the status of all pertinent regulatory authorizations in Canada and in the United States of America ("U.S.").

The Board's review of the commercial arrangements includes consideration of a number of items the applicant is required to provide in accordance with either the Part VI Regulations or in response to Board or intervenor information requests issued during the course of the hearing. These items include the following:

- the status of upstream and downstream transportation arrangements including, where possible, all transportation contracts, either in final form or as precedent agreements;

- the contractual obligations entered into between the Canadian seller and the U.S. buyer including executed contracts;

- any resale arrangements that occur beyond the international boundary sale point where such arrangements have a direct effect on the international sales agreement including filing of these downstream contracts; and

- in the case of sales to cogeneration facilities, the contractual obligations entered into between the cogeneration facility and the electric utility and the steam host.

In its review of the gas sales contracts entered into between the Canadian seller and the U.S.

buyer, the Board has in its recent Part VI deliberations made the following determinations:

- whether the contracts are likely to recover associated Canadian intraprovincial and interprovincial transportation costs;

- whether the contracts contain provisions which permit adjustments to reflect changing market conditions over the life of the contract;

- whether the contracts ensure that the volumes contracted for are likely to be taken; and,

- whether the contracts have the support of the Canadian producer(s) supplying the gas to the export project.

With respect to the second of the factors listed above, that of contractual responsiveness to changing market conditions, the Board recognizes that there may be cases where contracts are attractive to the parties involved, notwithstanding a lack of flexibility. In implementing the criterion relating to contract responsiveness, the Board operates on the presumption that, where contracts are freely negotiated at arm's length, they are in the public as well as private interest.

2.2.4 Views of Intervenors

Union Gas Limited ("Union") addressed four issues of generic concern to Part VI applications. These were the prematurity of some export applications, the evidence on markets which is required of a Part VI applicant, the gas supply which supports some Part VI applications by way of development contracts, and the assurance of takes under gas sales contracts. In addition, Union sought clarification on the approach the Board intends to take with respect to its division of review between Part VI and Part III matters in the GH-5-89 proceedings and in future hearings and requested reasons for the Board's decisions which would assist parties in preparing for future Part VI hearings.

On the subject of prematurity, Union was of the view that, if the Board was to hear an application that was premature, i.e. incomplete, then this could raise procedural problems as well as create substantive difficulty for the Board in meeting its own requirements for public hearings. Union suggested that applications should be reasonably complete in order to allow the fullest possible scrutiny at the public hearing. Further, Union suggested that it was inappropriate to consider substantive supporting material that was not available during the hearing, after the licence has been issued.

Union proposed two rules to prevent consideration of premature applications in the future. First, before an application is set down for hearing it must be well advanced, meaning that all necessary contracts be executed and filed in final form. This would include the export sales contract, downstream transportation contracts or, as a minimum, precedent agreements and, where applicable, associated supporting contracts such as power sales and steam sales agreements for cogeneration facilities. Union stated that the information filed should be sufficient to allow the Board to make a determination that there exists a reasonable expectation that gas would flow within a reasonably short period after the close of the hearing. Union defined this period as being eight to 12 months for most projects.

Union's second proposed rule was that the Board should establish reasonable deadline dates by which applicants must have filed all supporting documentation in final form, and that only minor changes or corrections would be permitted after that date. Union proposed that the deadline date would precede the deadline date for intervenors to file information requests.

Union expressed concern that applications be market-specific, that is, that there should be a definite contractual link between the Canadian seller and the end-use market. Union asked the Board to advise whether the Board's filing requirements for market information under Part VI was changing. Union also asked for clarification on whether the Board was prepared to issue export licences for terms and volumes not supported by established gas supply particularly where new facilities are required for the export. In this regard Union raised the question as to the relationship of the consideration of gas supply pursuant to Part VI filings versus Part III filings.

On the issue of contractual assurance of takes for proposed exports, Union advocated the need for

either minimum volume requirements under the sales contract, such as take-or-pay clauses, and/or contractual prohibition against displacement of the gas supply. Union was of the view that the existence of only an obligation to pay demand charges would not adequately provide assurance that volumes licensed for export would flow and that any facilities built would continue to be used.

The Consumers' Gas Company Ltd. ("Consumers'") expressed similar concerns to those of Union on the requirement that individual projects supporting a proposed facility expansion should be mature by the time the public hearing is concluded. Consumers' also stated that the Board should, in addition to the normal Part VI factors that it considers, take into account project-specific factors applicable to a determination of economic feasibility in its assessment of the Part VI licence applications. Consumers' was of the view that the same standards should apply to consideration of Part VI applications requiring facility expansion as apply to Part III applications.

Consumers' objected to the use of certificate or licence conditions as a means of obtaining evidentiary material supporting applications after the close of public hearings, because such evidence could not be thoroughly tested. Consumers' was also concerned that, although the filing requirements for Part VI applications were well known, it was not clear what weight the Board gave to the various components of its analysis of a Part VI application nor the depth of that analysis. Consumers' asked the Board to define what Consumers' termed "hurdle rates" for the factors considered under Part VI. Consumers' stated that, without this information, it was difficult for an intervenor to determine to what degree it should test filed material, and whether, in actual fact, such testing was even necessary, given that the Board might not consider it to be useful or might not use its assessment of any of this material to grant or deny an application. Consumers' requested that the Board advise whether in-depth review, as currently conducted by some intervenors, provided the Board with useful information and whether it should be continued. In this regard, Consumers' suggested that the standards and criteria the Board uses to assess Part VI applications be made known to all interested parties.

Consumers' expressed its concern related to specific conditions in the various contracts filed in support of Part VI applications. It expressed concern over price redetermination provisions which lacked binding arbitration clauses, and provisions in some contracts that allow the buy-down or the unilateral right to reduce daily contract quantities ("DCQ") in supply contracts. Consumers' stated that contracts or precedent agreements should be filed for each segment of the transportation chain. In addition, Consumers' considered that the power and steam sales contracts for cogeneration projects must also be filed in final form. Finally, with respect to regulatory approvals, Consumers' was of the view that the regulatory process should be well advanced at the time an application is heard, and, as a minimum, that applicants must show that requisite applications have been filed and that the overall process is sufficiently well advanced to provide parties with a fairly clear indication that approvals will be issued.

2.2.5 Views of the Board

The filing requirements for Part VI applications are contained in the Part VI Regulations as supplemented by additional filing requirements pursuant to the Market-Based Procedure. In this regard, the Board considers that it would be ideal to have all applications filed under Part VI absolutely complete to the extent contemplated under these filing requirements. The Board, however, recognizes that in certain instances timing and other constraints can limit an applicant's ability to bring forward finalized agreements and approvals.

Given these factors, the Board has exercised some degree of flexibility in the enforcement of the filing requirements for export licence applications and, in certain instances, the Board has reviewed applications under Part VI that could be considered to have certain parts missing. However, where final executed agreements are not available, the Board requires an explanation of the status of the outstanding material. In certain situations pro forma type agreements are accepted to provide all parties with a clear understanding of what the final form of the agreements will be and to allow parties to examine the proposed contractual arrangements.

Notwithstanding the foregoing flexibility, because of the role it has in the complaints procedure, the Board requires, without exception, that the export sales contract, or the operative arm's length arrangement between the buyer and seller, be filed in final and executed form with the export licence application. The Board has, in the past, accepted signed precedent agreements with attached pro forma contracts for the sales contract, but this was done under exceptional circumstances and was not intended to create a precedent for future filings.

The Board may even, albeit infrequently, decide to approve an export application in the absence of certain finalized agreements if it believes the export arrangements have been adequately explained, and, in such a case it may make the licence conditional on the supply and market arrangements remaining unchanged from those in evidence at the hearing. Furthermore, in reviewing an applicant's submission with respect to satisfying a licence condition, the Board may, where it considers it necessary, undertake its review in a public proceeding, thereby affording interested parties an opportunity to comment.

Finally, the Board understands the concerns of Consumers' and Union with respect to evidence related to the contractual chain and assurance of take. It is the Board's intention to further address these concerns at an early date.

2.3 Sunset Clauses

It has generally been Board practice in issuing a gas export licence to set an initial term of the licence for a short period of time during which, if the export of gas commences, the licence becomes effective for the full period approved by the Board. This condition in the licence is referred to as a sunset clause because the licence would expire if exports had not commenced within a specified timeframe. Inclusion of the sunset clause is intended to limit outstanding licences to those for which the gas actually flows within a reasonable period after the decision. The Board questioned each applicant concerning the acceptability of a sunset clause in the applied-for licence, and in each case the applicant indicated that a sunset clause would be acceptable.

Chapter 3

Brymore Energy Ltd. as Agent for Pawtucket Power Associates

3.1 Application Summary

By application dated 1 August 1989, as amended, Pawtucket, by its agent Brymore, sought, pursuant to Part VI of the Act, a natural gas export licence with the following terms and conditions:

Term	- from 1 November 1991 to 31 October 2011
Point of Export	- near Iroquois, Ontario
Maximum Daily Quantity	- 363 10^3m^3 (12.8 MMcf)
Maximum Annual Quantity	- 132 10^6m^3 (4.7 Bcf)
Maximum Term Quantity	- 2 648 10^6m^3 (93.5 Bcf)
Tolerances	- 10 percent per day and 2 percent per year

The gas proposed for export would be produced in Alberta and the Yukon from established reserves controlled by Columbia Gas Development of Canada Ltd. ("Columbia") and Opinac Exploration Limited ("Opinac").

The Yukon-sourced gas would be processed in British Columbia and transported on the Westcoast Energy Inc. ("Westcoast ") system for delivery to the NOVA Corporation of Alberta ("NOVA") system. NOVA would deliver the gas to TransCanada at Empress, Alberta and TransCanada would transport the gas to the international border near Iroquois, Ontario. The gas would then be transported on the Iroquois Gas Transmission System ("IGTS"), the Tennessee Gas Pipeline Company ("Tennessee") and the Valley Gas Company ("Valley Gas") systems for final delivery to the Pawtucket cogeneration facility.

The cogeneration facility's power output would be sold to NEP and its steam to Colfax, Inc. ("Colfax"). The facility would be constructed adjacent to the Colfax plant in Pawtucket, Rhode Island.

3.2 Gas Supply

3.2.1 Supply Contracts

Pawtucket signed contracts with two producers, Columbia and Opinac. The contracts dedicate specific reserves to meet DCQ. Augmenting these reserves are covenants within the contracts which dedicate reserves on a rolling basis during the term of the contracts in order to ensure sufficient reserves are dedicated to meet requirements.

The contract with Columbia provides 68 percent of the supply for the proposed export. The contract allows Columbia to reduce its DCQ, in whole or in part, on two years notice after three years have elapsed.

Brymore is managing and administering the gas supply and transportation for Pawtucket. The agreement between Brymore and Pawtucket states that Brymore will backstop the Columbia and Opinac volumes on a "reasonable efforts" basis from the gas supplies available to it as a marketer and will contract for additional gas supplies, on a short-term or long-term basis, if required by Pawtucket.

The contracts between Pawtucket and the two producers are discussed further in section 3.3.3 of these Reasons.

Table 3-1

Comparison of Estimates of Pawtucket's Established Gas Reserves With the Applied-for Volume

$10^6 m^3$ (Bcf)

Pawtucket[171]	**NEB**[2]	**Applied-for Volume**
2 236 (79)	2 096 (74)	2 648 (94)

1. as of 1 January 1990.
2. as of 31 December 1988.

3.2.2 Reserves

Table 3-1 shows that the Board's estimate of currently dedicated reserves is six percent lower than Pawtucket's estimate and 21 percent lower than the applied-for volume. Pawtucket's estimate of currently dedicated reserves is also lower than the applied-for volume by approximately 16 percent.

The discrepancy in estimates of reserves arises from varied interpretations of pool parameters in the Willesden Green Viking pool and several smaller pools. The Willesden Green Viking pool, which accounts for 33 percent of the total divergence in estimates of reserves, was interpreted by the Board as having a 22 percent smaller average net pay and a more conservative pool contouring than that used by Pawtucket in its estimation of reserves. The remainder of the differences in reserves estimates was due to smaller net pays and drainage areas attributed by the Board to other small pools.

The Board's analysis indicated that Pawtucket's gas reserves are contained in 39 gas pools located in 14 Alberta fields and one Yukon field. The pools are found mainly in Lower Cretaceous, Jurassic and Devonian horizons. Of Pawtucket's dedicated reserves, 26 percent are contained in the Evansburg and Willesden Green fields in Alberta and 26 percent in the Kotaneelee Field in the Yukon.

In summary, the Board's estimate of currently dedicated reserves is slightly lower than Pawtucket's estimate and significantly lower than the applied-for term volume. Pawtucket has stated that the producers have covenanted to dedicate further reserves on a rolling basis to ensure that no shortfall occurs.

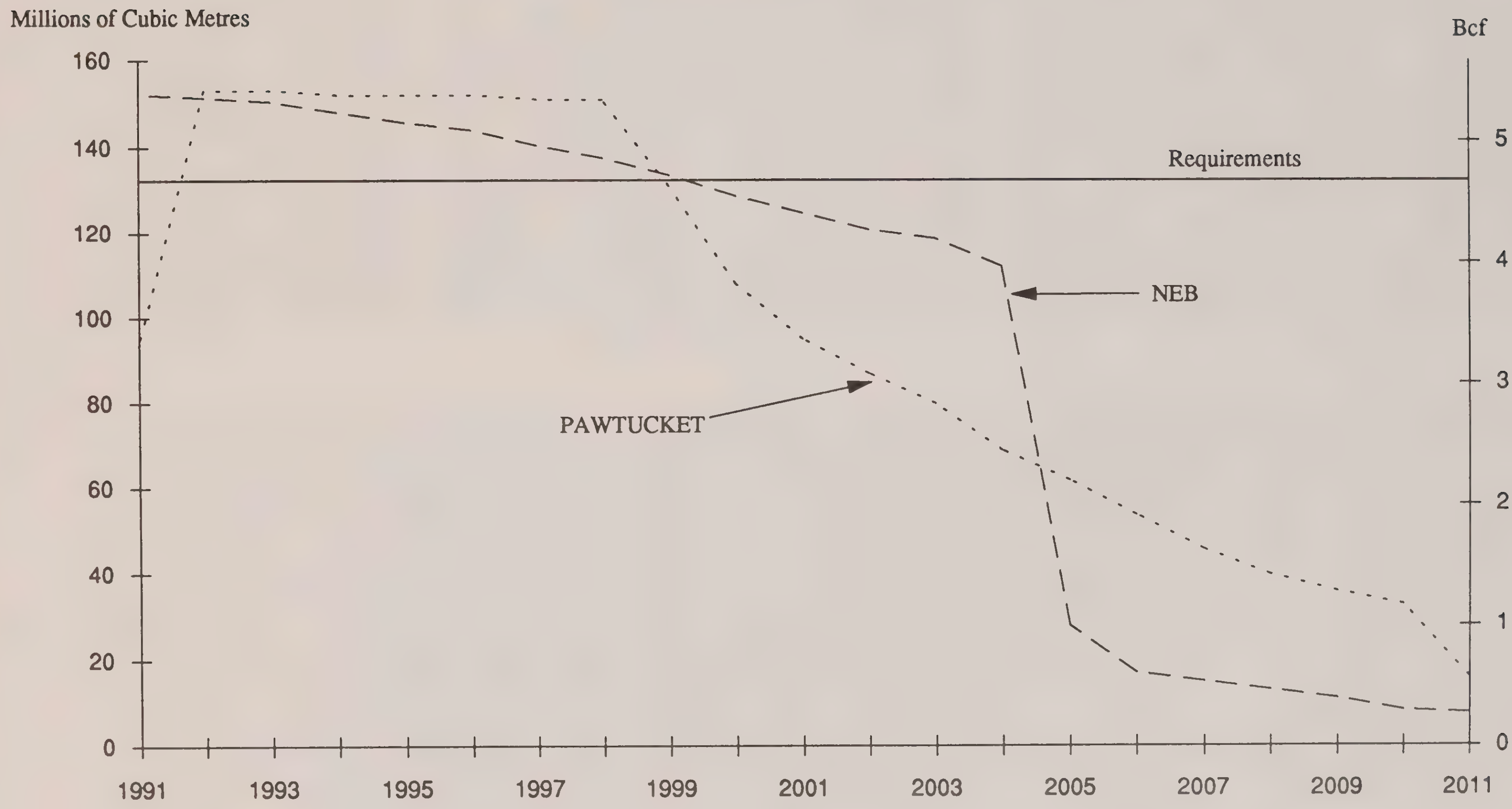
3.2.3 Productive Capacity

A comparison of the Board's and Pawtucket's estimates of productive capacity with the applied-for requirements is shown in Figure 3.1.

Pawtucket's estimate of productive capacity from its currently dedicated reserves was calculated at a 100 percent load factor and represents the technically or economically optimal configuration for the processing facilities. Pawtucket estimated that its current reserves dedication provides productive capacity sufficient to meet full requirements for eight years, at which time

Figure 3.1

COMPARISON OF ESTIMATES OF ANNUAL PRODUCTIVE CAPACITY FOR PAWTUCKET



Pawtucket submitted that covenants in the Columbia and Opinac gas purchase contracts will ensure the dedication of additional supply.

Pawtucket indicated that both Columbia and Opinac are exploration corporations, actively drilling and exploring for natural gas in western Canada, and that the shortfall in reserves and deliverability arises sufficiently far into the future that Columbia and Opinac will have ample time to develop further reserves to meet contractual obligations.

Both Columbia and Opinac provided corporate supply/demand balances. These corporate supply/demand balances indicated that Columbia could meet its total requirements until 2005, but that Opinac could meet its requirements only until 1998, assuming it did no further drilling.

The Board's estimate of productive capacity from Pawtucket's dedicated reserves also indicates that Pawtucket can meet its full requirements for approximately eight years and that it can maintain productive capacity at a level slightly below its requirements until the year 2004. Thereafter, there is a significant shortfall in supply relative to the applied-for requirements. The Board's projection of productive capacity also assumes a 100 percent load factor.

3.3 Market and Commercial Arrangements and Regulatory Status

3.3.1 Market

The gas proposed for export would be used to fuel Pawtucket's fully financed 61.3 MW cogeneration facility located on a 3.3 acre site leased from Colfax near Pawtucket, Rhode Island. Aside from the No. 2 fuel oil that would be used as the back-up fuel at the cogeneration facility, the facility would be fired entirely by the applied-for gas.

Pawtucket is a Massachusetts Limited Partnership whose general partner is EMI/Pawtucket Inc. EM I/Pawtucket Inc. is a wholly-owned subsidiary of Energy Management, Inc., an energy development company in New England.

Colfax, the thermal host, is a manufacturer of shortening and vegetable oils for the commercial and consumer markets. NEP, the power purchaser, is a wholesale electric company that owns generating facilities in the states of Massachusetts, New Hampshire and Rhode Island.

The combined service territory of NEP affiliated retail companies is 11 655 square kilometres (4,500 square miles), with a total population of approximately 2.7 million. The largest cities include Worcester, Massachusetts and Providence, Rhode Island. NEP is a member of the New England Electric Power Pool ("NEPOOL"). NEPOOL coordinates the planning and operation of the generation and bulk transmission facilities of its 93 members. An annual electric power growth rate for NEP of 1.8 percent is forecast for the period 1989 to 2004.

The cogeneration facility would be designated dispatchable or must-run on a month-to-month basis and is expected to provide NEP with approximately 788,400 MW.h of electric energy annually. The facility will be located in the service territory of Blackstone Valley Electric, but will be connected to an NEP subsidiary, Narragansett Electric, whose service territory is less than one kilometre (0.6 miles) from Colfax.

By an agreement dated 23 January 1990 with Pawtucket, Brymore is to manage and administer Pawtucket's gas supply and transportation commitments for a period of 20 years. Under the agreement, Brymore is also to identify and assist in the final negotiations with any new suppliers should any of the two current gas sales contracts be terminated. Brymore is also to provide backstopping services on a reasonable efforts basis.

Pawtucket projected a load factor of 91 percent for the facility on the basis that the facility would be dispatchable high on the NEPOOL dispatch curve and given the low incremental cost of natural gas and high plant efficiency.

Brymore has the right to ship gas should transportation capacity not be fully utilized by Pawtucket during any day.

The facility was expected to be turned over to Pawtucket by Ebasco, Inc., the project contractor, by approximately 25 December 1990.

Pawtucket testified that a 20-year licence term was necessary for the following reasons:

- corporate warranties to provide the full 20-year term volume of gas had been provided by Columbia and Opinac;

- Pawtucket's power sales agreement, which would provide the cash flow to pay transportation demand charges, is for 20 years;

- the precedent transportation agreements with the Canadian and U.S. pipelines transporting the applied-for gas are all 20-year firm service agreements;

- long-term financing with a primary term of 15 years had been obtained for the Pawtucket plant. Pawtucket submitted that this, coupled with the need to attract and hold equity investment, bolsters the need for the 20-year licence; and,

- the U.S. Department of Energy/Office of Fossil Energy ("DOE/FE") import authorization is for the full term of 20 years.

Pawtucket acknowledged that it had applied to the Alberta Energy Resources Conservation Board ("AERCB") for a 15-year removal permit.

3.3.2 Transportation

Gas for the proposed export from the Kotaneelee field in the Yukon would be shipped to the Fort Nelson gas plant in British Columbia for processing. It would then be transported by Westcoast to the interconnect with NOVA at Gordondale, Alberta. NOVA would transport this gas plus the Alberta-sourced gas to the interconnect with TransCanada near Empress, Alberta for delivery to IGTS near Iroquois, Ontario. IGTS would forward the gas to the Tennessee system interconnect at Schoharie County, New York. Valley Gas would transport the gas from its interconnect with Tennessee near Lincoln, Rhode Island to the cogeneration facility.

Pawtucket has executed a service agreement dated 1 October 1989 with NOVA for 398 10^3m^3/d (14.1 MMcfd) of firm transportation service for a period of 20 years commencing 1 November 1991.

Pawtucket and TransCanada executed a precedent agreement dated 1 May 1989, as amended, for 360 10^3m^3/d (12.7 MMcf/d) of firm transportation service. The term of the firm service contract is to extend from no earlier than 1 November 1991 to 31 October 2011. Pawtucket has requested an increase in the daily volume to 363 10^3m^3 (12.8 MMcf).

As the shipper on both NOVA and TransCanada, Pawtucket would be responsible for the associated demand charges. With respect to demand charge payments on TransCanada, Pawtucket stated that, should the project sponsors encounter operating problems which they are unable to rectify, the financiers will assume the operation of the facility and the obligation to pay fixed operating costs, including TransCanada demand charges. NEP also has the right, subordinate to the financiers', to step in and operate the facility and be responsible for fixed operating expenses.

Twenty-year firm transportation service on IGTS and Tennessee was arranged by Pawtucket under precedent agreements dated 16 and 14 December 1988 respectively. Pawtucket has also signed a firm off-peak transportation agreement with Valley Gas dated 27 March 1990. Under this agreement, Valley Gas would be entitled to divert Pawtucket's gas supply to its own system for up to 25 days per year during peak periods. In exchange, Valley Gas would provide Pawtucket with an equivalent amount of No. 2 fuel oil to replace the diverted gas.

The lateral from Valley Gas' existing pipeline to the cogeneration facility has already been constructed and will be operated by Pawtucket.

Facilities additions on IGTS and Tennessee were approved by the Federal Energy Regulatory Commission ("FERC") on 14 November 1990.

3.3.3 Gas Sales Contracts

Pawtucket has entered into a contract with each of Columbia and Opinac. Both contracts are for 20-year terms commencing on the later of

1 November 1991 or the date upon which all necessary pipeline facilities are in place. Both contracts are also subject to several conditions precedent, including receipt of all necessary Canadian and U.S. regulatory approvals, the finalization of all Canadian and U.S. transportation arrangements, approval of the contracts by certain parties, the timely construction of the facility and the arrangement of project financing. It was stated that the date by which the conditions precedent were to be satisfied was being amended to November 1994.

The contracts provide that volumes not nominated by Pawtucket may be marketed for off-system sale.

The pricing structure in each contract contains a commodity charge component only. Pawtucket, being the shipper on both NOVA and TransCanada, would incur the demand charges for transportation directly.

Other provisions unique to each contract are discussed below.

3.3.3.1 Columbia Gas Development of Canada Ltd.

Pawtucket and Columbia executed a contract dated 27 April 1989 which provides for the daily delivery of up to 241 10^3m^3 (8.5 MMcf) of gas at the NOVA inlet.

Should Pawtucket take, on average, less than 70 percent of the Maximum Daily Quantity ("MDQ") over a two-year period, then Columbia may reduce the MDQ for the remainder of the contract term to 70 percent of actual nominations over the two-year period. Pawtucket is also contractually committed to take gas from Columbia at the same percentage as from all other suppliers.

The commodity charge component of the price is adjusted monthly from an initial level of \$ U.S. 1.24/GJ (\$ U.S. 1.33/MMBtu). Adjustments to the commodity charge would be comprised of changes in the New York Harbour Spot Price of 2.2 percent sulphur No. 6 fuel oil, Tennessee's current average cost of purchased gas, and NEP's weighted average delivered coal cost. Changes in these fossil fuel prices would have a weighting of 25, 50, and 25 percent respectively. Provision is made for adjusting the formula should NEP's consumption of high sulphur fuel oil decrease.

Based on these contract terms, the estimated price at the Alberta border as of January 1990 was \$ Cdn. 2.02/GJ (\$ Cdn. 2.17/MMBtu).

Redetermination of the contract price is permitted every two years following the third contract year. Should parties be unable to agree to redetermination within three months, then Columbia may set the price at either the weighted average NOVA inlet price paid by NEP and its affiliates, or the Average Alberta Market Price ("AAMP"). Further, either party may also then terminate the contract effective two years from the last redetermination date. There is no provision for arbitration in the contract.

The contract also allows Columbia to reduce the MDQ, either in whole or in part, on two years notice following the third contract year.

3.3.3.2 Opinac Exploration Ltd.

Pawtucket and Opinac executed a contract dated 6 April 1989 providing for the daily delivery of up to 170 10^3m^3 (6.0 MMcf) of gas at the NOVA inlet.

Should Pawtucket's nominations, on average, be less than 70 percent of the MDQ over a two-year period, then Opinac may elect to reduce the MDQ for the remainder of the contract term by the percentage difference between 70 percent of the MDQ and the percentage actually taken over that period.

The commodity charge component of the price is adjusted monthly from an initial level of \$ U.S. 1.28/GJ (\$ U.S. 1.38/MMBtu). Adjustments to the commodity charge would be comprised of changes in the same basket of fossil fuel prices as in the Pawtucket/Columbia contract. However, the weighting of the fuel prices would be 50 percent oil, 25 percent gas, and 25 percent coal.

Based on these contract terms, the estimated price at the Alberta border as of January 1990 was \$ Cdn. 2.25/GJ (\$ Cdn. 2.41/MMBtu).

The contract price is subject to redetermination in every fifth year. It is intended that the redetermined price be comparable to other long-term firm base-load gas supplies at LDC city-

gates in Connecticut, Massachusetts and Rhode Island, and that it allow the cogeneration facility to be dispatched as a base-load facility. Should parties not be able to agree to a redetermined price prior to a specified date, then the price would be set at the second of the two streams above until agreement is reached.

3.3.4 Power Sales Agreement

The sale of electricity from the cogeneration facility would be pursuant to an agreement, as amended, between Pawtucket and NEP. The agreement will continue for an initial term of 20 years from the commencement date of operations. The agreement may be extended for an additional five-year period.

The cogeneration facility would be designated dispatchable or must-run by NEP on a monthly basis, with the New England Power Exchange ("NEPEX") controlling the actual rate of dispatch. Pawtucket expects the plant to be dispatched as a base-load facility, due to plant efficiency and incremental dispatch cost criteria. NEPEX may dispatch the plant down to 85 percent of its capability, including a maximum of 25 stop/starts annually. The price for electricity produced includes a monthly capacity charge and an energy charge. Gas to the plant would be priced to ensure operation at a 75 percent capacity factor. The Applicant stated that the monthly demand charge is paid based on plant availability regardless of the power produced. Should the plant lose its QF status, it would continue to operate based on FERC regulations, but at a rate no higher than provided for by the power purchase agreement. The sale of electricity from the plant does not require wheeling.

3.3.5 Thermal Energy Sales Agreement

The proposed sale of thermal energy would be pursuant to the energy services agreement dated 31 March 1987, as restated and amended, between Pawtucket and Colfax. The agreement will remain in effect for a period of 25 years from the commercial operation date, and includes provision for extension. Colfax will take a minimum amount of steam to ensure the maintenance of the project's QF status. Steam will be priced at 75 percent of Colfax's avoided boiler fuel costs. The Pawtucket project, as part of its contractual obligations, includes a user fee payable to Colfax. Colfax will pay all costs should Pawtucket be required, because of equipment failure, to provide Colfax with steam from its auxiliary boiler. If the steam host terminates the agreement, Pawtucket may continue to use the site for thermal sales to third parties or to produce more electricity from the waste-heat.

3.3.6 Regulatory Status

On 1 August 1989, both Columbia and Opinac applied to the AERCB for long-term removal permits. The requested term was for the period 1 November 1989 to 31 October 2004.

Pawtucket indicated that the AERCB was evaluating these applications and Pawtucket expected that both Columbia and Opinac would be granted removal permits within the next few months.

The volumes to be supplied by Columbia from the Kotaneelee field in the Yukon do not require removal authorization.

Pawtucket received DOE/FE import authorization on 15 November 1990 and FERC QF status on 2 April 1989.

3.4 Views of Intervenors

Consumers' and Union opposed the export licence application by Pawtucket (and the related portions of the facilities application by TransCanada). The opposition by Consumers' was based on the argument that the Pawtucket application lacked a long-term gas supply contract for 68 percent of the applied-for daily volume. Union opposed the application based on concerns regarding gas supply, contractual assurances of take and the gas sales contract. The views of Consumers' and Union and the reply by Pawtucket are discussed below.

Concerns over clause 2.05 of the Pawtucket/Columbia gas purchase agreement formed the basis of the Consumers' argument. The clause gives Columbia the unilateral right to reduce the daily and total contract quantities on two years' notice after the third year of contract operation. Consumers' argued that this clause

effectively makes the Pawtucket/Columbia contract a short-term one. Consumers' argued that, as the backstopping arrangement in the Pawtucket/Brymore management agreement was not firm, the short-term nature of the Pawtucket/Columbia contract remained unchanged.

Union expressed concern that Pawtucket's own evidence indicated that deliverability deficiencies would be experienced commencing in the eighth year of the twenty-year term. Union was also concerned that there was no contractual commitment for Pawtucket to take the gas and that Pawtucket was not prevented from purchasing other replacement supply. Further, Union maintained that the gas sales contract should be viewed essentially as a renewable short-term contract. In support of its argument, Union cited clause 2.05, discussed above, and the lack of binding contractual arbitration provisions regarding price renegotiation.

Pawtucket, in rebuttal of the arguments of Consumers' and Union that the contract should be viewed as short-term, conceded that clause 2.05 of the Pawtucket/Columbia contract does empower Columbia to reduce the DCQ to as low as zero, but argued that it was highly unlikely that Columbia would exercise this option for the following reasons:

- there is an initial unbreakable five-year term of the contract;

- Columbia has stated on the record that it treats the applied-for export as a 20-year commitment;

- Columbia's initially dedicated reserves to this project are in excess of 10 years;

- Columbia would only exercise its right to reduce the DCQ if it found a better market. The Pawtucket contract is market-based and thus it would be difficult for Columbia to find a better market; and,

- the advanced stage of the project also makes it unlikely that Columbia would back away from the project.

In response to Union's concern regarding the lack of contractual assurances of take, Pawtucket stated that the Board should not impose a "minimum take test", as advocated by Union.

3.5 Views of the Board

With regard to the Pawtucket/Columbia gas purchase contract, the Board agrees with the position advanced by Consumers' and Union that Columbia's right, as expressed in clause 2.05, to unilaterally reduce the DCQ to zero on two years' notice could be construed as constituting a short-term contract. However, the Board does not agree that this contractual provision, per se, is a sufficient reason to deny an export application.

The Board is prepared to accept the argument of Pawtucket that the Columbia supply arrangement is intended to be a long-term commitment, that the decontracting option could be exercised no earlier than the fifth year of the contract and finally, that Pawtucket's responsibility for demand charges on TransCanada over the life of the 20-year firm service ("FS") contract provides an incentive to replace any Columbia supply that might be decontracted with an alternative source of Canadian gas. The two-year notice period contained in clause 2.05, Brymore's backstopping commitment, and Pawtucket's contractual right to pass through to its customer, NEP, the costs of any replacement supply, should provide Pawtucket with adequate lead time and flexibility to obtain an alternative Canadian supplier.

The Board also agrees with Union that there is a substantial deficiency in productive capacity relative to the applied-for term.

Pawtucket submitted estimates of reserves in support of its export application that were sufficient from a volumetric standpoint to support approximately 17 years of full requirements. The Board's estimate of reserves is somewhat less, providing for about 16 years of full requirements. The Board's projection of productive capacity from these reserves suggests that Pawtucket could maintain supply at a level approximately equivalent to its requirements for about 14 years of its applied-for term of 20 years, after which there is an increasing shortfall in productive capacity.

Based on the contractual evidence filed, the Board is satisfied that the downstream markets for the

electricity and steam produced by the cogeneration facility are secure and that the facility would operate at a high load factor. The Board notes that project financing, DOE/FE import authorization and FERC QF certification have been received. The Board also notes that the cogeneration facility was expected to be completed by late December 1990.

The Board recognizes that transportation on the NOVA, TransCanada, IGTS, Tennessee, and Valley Gas systems has been secured. Further, the Board is satisfied that all fixed costs of transportation in Canada would be recovered, given that Pawtucket is the shipper on NOVA and TransCanada and is thus directly responsible for those demand charges.

The Board is satisfied that the pricing provisions contained in the gas sales contracts permit adjustments in the export price to reflect changing market conditions. The Board also recognizes the flexibility that exists in the Pawtucket/Opinac agreement through the inclusion of renegotiation provisions. The Board is satisfied that the provisions in both contracts would ensure the ability of the contracting parties to respond to changing circumstances in the export market.

The Board has reviewed the gas contracts and has noted that they have been negotiated at arm's length.

The Board has not been persuaded by the arguments of Consumers' and Union that an export licence should not be granted to Pawtucket because the export contracts lack an explicit minimum take provision. The Board is of the view that, because export contracts are negotiated at arm's length to meet the needs of individual buyers and sellers, it would be inappropriate to impose a "minimum take test".

The Board notes that the Canadian producers involved in the project have endorsed the proposed export by virtue of their having executed gas sales contracts.

Given the evident deficiency in reserves and productive capacity, the Board has examined whether there is a commercial necessity for a 20-year licence term. The Board notes that many of the associated contractual and commercial arrangements including the primary term of the long-term financing and the AERCB removal permit would have terms of less than 20 years.

On the basis of the Board's analysis of Pawtucket's supply, it is apparent that productive capacity can be maintained at a level equal to requirements until about 2005. The Board's assessment of available productive capacity is somewhat more optimistic than that of Pawtucket in this regard. The Board also recognizes that the contracts with Columbia and Opinac contain certain covenants providing for the dedication of additional supply. However, the Board is not satisfied that the evidence submitted by Pawtucket with regard to supply and the commercial necessity of the applied-for licence term is adequate to support the issuance of a 20-year export licence.

The Board notes that Pawtucket agreed to the inclusion of a sunset clause in the applied-for licence.

3.6 Decision

The Board has decided to issue a gas export licence to Pawtucket, subject to the approval of the Governor in Council. Appendix IV contains the terms and conditions of the licence, including a condition that the term of the licence shall commence on 1 November 1991 and shall end on 1 November 1993, unless exports have commenced under the licence on or before 1 November 1993, in which case the term would end on 31 October 2006.

Chapter 4

Canadian Occidental Petroleum Limited

4.1 Application Summary

By application dated 9 August 1989, as amended, Can Oxy applied, pursuant to Part VI of the Act, for a natural gas export licence with the following terms and conditions:

Term	- Beginning 1 November 1991 and extending for a term of 15 years
Point of Export	- near Niagara Falls, Ontario
Maximum Daily Quantity	- 433 10^3m^3 (15.3 MMcf)
Maximum Annual Quantity	- 158 10^6m^3 (5.6 Bcf)
Maximum Term Quantity	- 2 373 10^6m^3 (83.8 Bcf)
Tolerances	- 10 percent per day and 2 percent per year

The gas reserves in support of the proposed export would come from established reserves owned by Can Oxy and located in Alberta. The gas would be transported on NOVA within Alberta and on TransCanada to the Niagara Falls export point. From the international border, the gas would then be shipped on the Transcontinental Gas Pipe Line Corporation ("Transco") and Long Island Lighting Company ("LILCO") systems for delivery to Old Bethpage, New York.

The gas proposed for export would be used as fuel at Long Island Cogeneration Limited Partnership's ("LICLP") 79 MW gas-fired combined cycle cogeneration facility located in Old Bethpage, New York. LILCO would purchase the electricity, while an as yet unidentified industrial entity on Long Island, New York, would purchase the steam.

4.2 Gas Supply

4.2.1 Supply Contracts

Since Can Oxy intends to supply the proposed export with gas from its own pools and not contract for its supply from other producers, no gas supply contracts were required. The gas sales agreement between Can Oxy and LICLP contains a corporate warranty whereby Can Oxy warrants to cover any additional costs incurred by LICLP should Can Oxy fail to provide the requested volumes.

These contract arrangements are discussed further in section 4.3.3 of these Reasons.

4.2.2 Reserves

Table 4-1 shows that the Board's estimate of Can Oxy's contracted remaining marketable gas reserves is practically identical to Can Oxy's estimate. Both estimates exceed the applied-for volume by some 65 percent.

Can Oxy's estimate of reserves included proven and probable reserves from 16 areas in Alberta. The estimate of probable reserves made up 19 percent of the total estimate.

The minor discrepancy in estimates of reserves is due to the cumulative effect of small differences in interpretation of various reservoir parameters.

The Board's estimate of reserves for several McMurray pools located in northeast Alberta is lower than Can Oxy's primarily due to the Board's interpretation of drainage area assigned to individual pools. However, the Board's reserves are greater than Can Oxy's in western Alberta due mainly to higher recovery factors in Basal Belly River and Leduc pools and interpretation of reservoir mapping in thrust-fault controlled pools such as in the Findley Field.

Table 4-1

Comparison of Estimates of Can Oxy's Established Gas Reserves With the Applied-for Volume

10^6m^3 (Bcf)

Can Oxy[1]	NEB[2]	Applied-for Volume
4 006 (141)	3 924 (139)	2 373 (84)

1. as of 1 January 1989.
2. as of 31 December 1988.

In its analysis, the Board recognized reserves for 23 fields that are located in the 16 areas claimed by Can Oxy. There were 97 gas pools within the 23 fields recognized. One-third of the pools are located in northeast Alberta in Lower Cretaceous sands. The remainder of the pools are scattered throughout Alberta, mainly in single-well pools. Sixty-three percent of the pools for which Can Oxy has submitted reserves have reserves estimated by the Board to be less than 100 10^6m^3 (3.5 Bcf). The Board considered over two-thirds of the reserves classified as probable by Can Oxy to be proven reserves.

In summary, although estimates differ for some individual pools and areas, the Board's estimate of total reserves agrees very closely with Can Oxy's estimate. Both estimates of reserves are well above the applied-for volume.

4.2.3 Productive Capacity

A comparison of the Board's and Can Oxy's estimates of productive capacity with the applied-for requirements is shown in Figure 4.1.

Can Oxy provided a forecast of productive capacity from the lands it had dedicated to the export proposal which demonstrated deliverability in excess of requirements throughout the forecast period. Can Oxy estimated its productive capacity by field using the lesser of the maximum field wellhead deliverability or the maximum gathering and processing capacity.

The Board's estimate of productive capacity is higher than Can Oxy's and similarly shows supply in excess of requirements throughout the forecast period. The Board's projection of productive capacity was adjusted to reflect unused productive capacity relative to the applied-for requirements.

4.3 Market and Commercial Arrangements and Regulatory Status

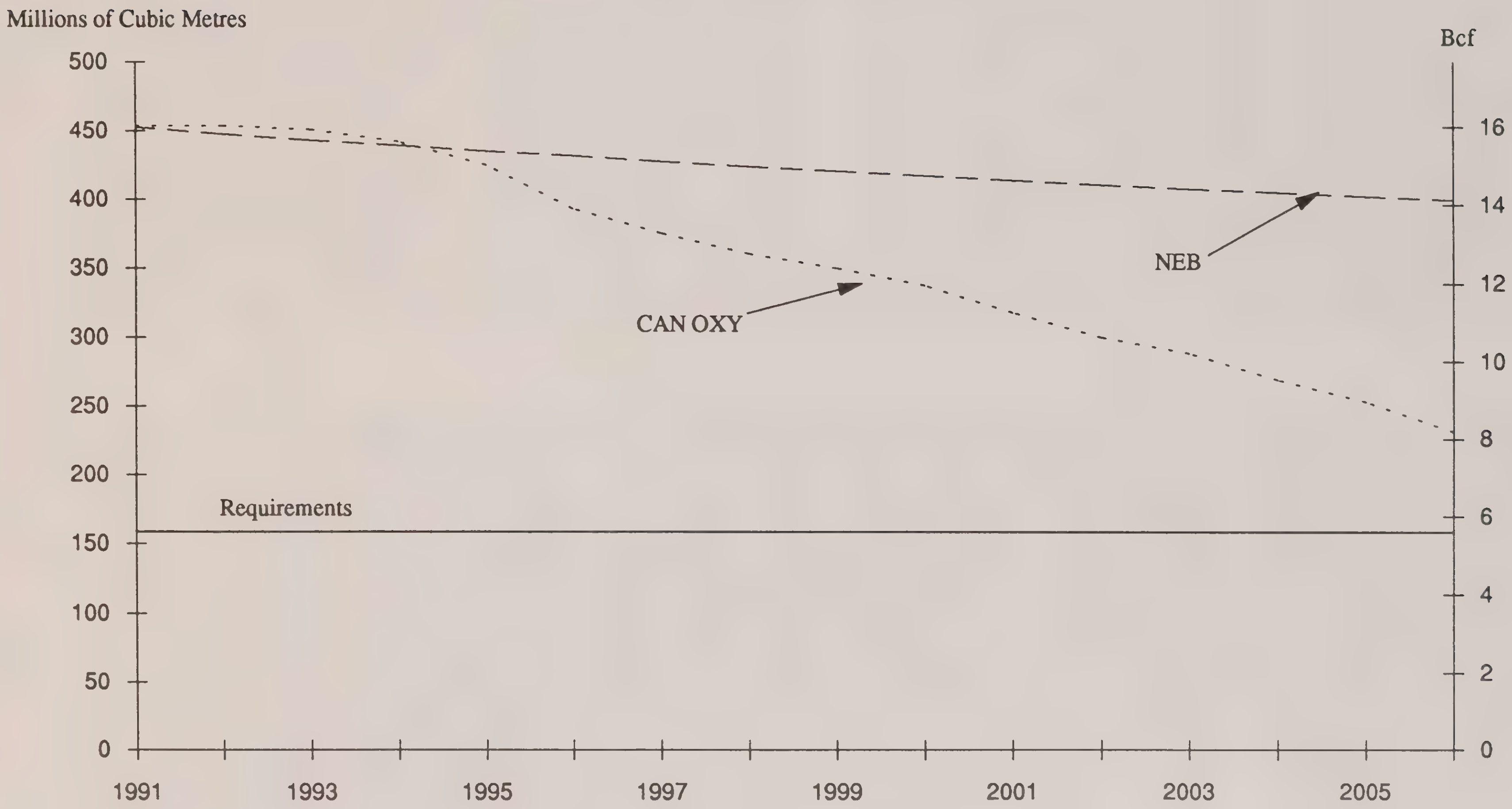
4.3.1 Market

The gas proposed for export would be used to fuel a 79 MW cogeneration facility located in Old Bethpage, New York. The plant is expected to be in commercial operation in June 1992.

LILCO, the power purchaser, is a combined electric and gas utility that serves Long Island, New York. The cogeneration plant is a must-run facility that is designed to generate approximately

Figure 4.1

COMPARISON OF ESTIMATES OF ANNUAL PRODUCTIVE CAPACITY FOR CANADIAN OCCIDENTAL



600,000 MW.h of electric energy annually. Purchases from the cogeneration facility will aid LILCO in maintaining its reserve margin requirements as a member of the New York Power Pool.

Can Oxy stated that $ 2 million had been committed to the development budget and that $ 10 million in equity had also been committed, thereby ensuring 50 percent of equity financing for the project.

Because the LICLP plant would be a base-load facility with Can Oxy being the sole gas supplier, and because of the up to 80 percent take-or-pay obligations in the sales contract, Can Oxy has forecast an annual load factor of 96 percent for the proposed export sale.

4.3.2 *Transportation*

The gas would be shipped within Alberta on NOVA and from Empress, Alberta to Niagara Falls, Ontario on the TransCanada system. In the U.S., transportation would be provided by Transco and LILCO.

In Canada, Can Oxy has made arrangements with NOVA for firm transportation service. With respect to transportation on TransCanada, Can Oxy has executed a precedent agreement dated 9 May 1989, as amended 23 February 1990 and 22 October 1990. In addition, Can Oxy has executed a financial assurances agreement with TransCanada dated 23 February 1990.

In the U.S., where the buyer is responsible for transportation arrangements, LICLP and Transco have an executed precedent agreement dated 5 March 1988. Transco has agreed to install new facilities connecting or expanding existing capacity for which FERC approval was granted on 13 September 1990. LICLP executed a gas transportation agreement dated 23 March 1989 with LILCO to provide local transportation to the cogeneration facility. While LILCO has sufficient pipeline capacity to transport the proposed volumes, a 2.5 kilometre (1.6 mile) pipeline will need to be constructed to connect the cogeneration plant to the existing pipeline. An application for this connector was made in March 1990 to the New York State Public Service Commission ("NYSPSC").

4.3.3 *Gas Sales Contract*

Can Oxy and LICLP have executed a gas purchase and sales agreement dated 1 May 1989.

The agreement includes a number of conditions precedent including the standard requirement that the two parties obtain the necessary import and export authorizations and transportation agreements. The agreement also stipulates that a firm commitment for financing be secured, that construction of the cogeneration plant commence on or before 1 July 1991, and that the plant start commercial operations on or before 31 December 1992. In the event that any of these conditions are not satisfied, either party may terminate the agreement on 60 days notice.

The agreement, under which LICLP agrees to purchase its total gas requirements for the cogeneration plant, will remain in force from the date of its execution until 15 years after the date of commencement of commercial operations. There is also a provision to extend the term by an additional five years, subject to regulatory approvals.

The MDQ in the agreement is 16 136 GJ (15,300 MMBtu) which includes the cogeneration plant's total requirements plus an allowance for transportation fuel and losses on U.S. pipelines.

The agreement contains a take-or-pay provision set at 70 percent of the MDQ in the first year and 80 percent thereafter, and is termed the minimum annual quantity ("MAQ"). Gas paid for but not taken in any particular year may be taken in subsequent years as make-up volumes so long as the quantities taken are in excess of the MAQ.

With respect to the price that would be paid for the gas, Can Oxy stated that the agreement stipulates a base price at the Niagara Falls export point of $ U.S. 2.37/GJ ($ U.S. 2.50/MMBtu) as of 1 January 1989 which would escalate on the basis of an index which consists of equal weights for prices of No. 6 heavy fuel oil in New York Harbour and of the wholesale price for natural gas in certain markets in the New York City area. The Applicant estimated that the contract price at Niagara Falls on 1 January 1990 would have been $ Cdn. 3.57/GJ ($ U.S. 3.76/MMBtu) while the

Alberta border price would have been \$ Cdn. 2.58/GJ (\$ U.S. 2.72/MMBtu).

The contract price for the last five years of the agreement would be subject to a ceiling equal to relevant gas prices in New York City and a floor based on the ratio of the contract value and market prices at the New York City gate. LICLP is obligated to pay demand charges on TransCanada based on a 100 percent load factor.

The agreement does provide for arbitration with respect to the references to be used for the price index.

4.3.4 Power Sales Agreement

The proposed sale of electricity from the Old Bethpage cogeneration plant would be pursuant to the parallel generation agreement, dated 4 March 1988, as amended, between LILCO and LICLP. The agreement will continue for a period of 20 years from the commencement of commercial operations which must occur no later than 31 December 1992. The agreement may be extended or renewed.

The Old Bethpage cogeneration plant is a base-load facility. LILCO will pay the greater of \$ 0.06/kW.h or the avoided cost tariff, approved by the NYSPSC, for the first five years of the contract term. The percentage of the avoided cost tariff to be paid declines to 95 percent during the next five years and declines to 90 percent during the last ten years of the contract term. The electricity sold from the Old Bethpage facility does not require wheeling by third parties.

4.3.5 Thermal Energy Sales Agreement

The Applicant did not provide the Board with an executed thermal energy sales agreement. However, it stated that the cogeneration facility will be located in an industrial area with a number of potential steam-users with steam requirements of up to four times the amount that needs to be contracted for. The Applicant stated that it did not have a contract at the time of the hearing because it was attempting to negotiate the best steam sales arrangement possible, but that it had every confidence that a contract could be signed at any time. The Applicant has undertaken to file a thermal sales contract upon execution.

4.3.6 Regulatory Status

Can Oxy was granted Energy Removal Permit GR90-13 on 3 May 1990 by the AERCB. The permit authorizes Can Oxy to remove sufficient gas from the province to satisfy its requirement for the proposed export over the full term of the proposed licence.

LICLP applied to the DOE/FE for import authorization on 27 October 1989 and approval was received on 29 September 1990. The facility has received its FERC QF status.

4.4 Views of the Board

The Board is satisfied as to the adequacy of Can Oxy's supply relative to its applied-for requirements on the basis of the supply information which has been submitted.

The Board recognizes that transportation on all required pipelines has been arranged and the Board is satisfied that transportation costs in Canada for the proposed export will be recovered by virtue of the fact that LICLP is obligated to pay demand charges on TransCanada regardless of the volume actually transported.

The Board notes that the gas contracts have been negotiated at arm's length.

With respect to assurances of take, it is the Board's view that the proposed export will operate at a high load factor given that, as previously mentioned, the demand charges must be paid; that Can Oxy is to be the exclusive supplier of gas to the cogeneration facility; and that the contract contains a take-or-pay provision of 70 percent of the MDQ in the first year and 80 percent thereafter.

The Board is satisfied that the downstream market for the electricity produced by the cogeneration facility is secure. The Board is of the view that, given the plants close proximity to a number of possible steam hosts, there exists a strong likelihood that a steam sales contract will be finalized. The Board notes that project financing, DOE/FE import authorization and

FERC QF certification have been received. The Board also notes the cogeneration facility's expected completion date of June 1992.

Can Oxy owns the gas proposed for export and, as a result, evidence of producer support was not necessary.

4.5 Decision

The Board has decided to issue a gas export licence to Can Oxy, subject to the approval of the Governor in Council. Appendix IV contains the terms and conditions of the licence, including a condition that the term of the licence shall commence on 1 November 1991 and shall end on 1 November 1993, unless exports have commenced under the licence on or before 1 November 1993, in which case the term would end on 31 October 2006.

Encogen Four Partners, L.P.

5.1 Application Summary

By application dated 6 November 1989, as amended, Encogen sought, pursuant to Part VI of the Act, a natural gas export licence with a term of 15 years. The gas would be exported at a point near Chippawa, Ontario.

Encogen applied for a licence with the following terms and conditions:

Term	- 15 years commencing 1 November 1991 or as soon thereafter as gas can be made available
Point of Export	- near Chippawa, Ontario
Maximum Daily Quantity	- 425 10^3m^3 (15.0 MMcf)
Maximum Annual Quantity	- 155 10^6m^3 (5.5 Bcf)
Maximum Term Quantity	- 2 327 10^6m^3 (82.1 Bcf)

The proposed export volumes would be produced from reserves owned by Sceptre Resources Limited ("Sceptre") in Alberta and Saskatchewan

The export volumes produced in Saskatchewan would be transported by TransGas Limited ("TransGas") to the inlet of the TransCanada system. In Alberta, the gas would be delivered to Empress through the NOVA system. TransCanada would provide transportation from the TransGas and NOVA systems to the international boundary at Chippawa, Ontario. In the U.S., the gas would be transported on the Empire State Pipeline ("Empire") to the facilities of National Fuel Gas Distribution Corporation ("National Distribution") at Tonawanda, New York. National Distribution would, in turn, deliver the volumes to a cogeneration plant to be built in Buffalo and owned by Encogen.

Niagara Mohawk Power Corporation ("Niagara Mohawk") would purchase the electricity and the American Brass Company, L.P. ("American Brass") would purchase the steam.

5.2 Gas Supply

5.2.1 Supply Contracts

Encogen has executed a 15-year supply contract dated 4 November 1989, as amended on 17 January 1990, with Sceptre, which is renewable on a year-to-year basis after the 15-year term.

Under the terms of the contract, Sceptre has contractually dedicated specific pools in Saskatchewan to the execution of the contract. These reserves amount to approximately one-half of the project's requirements. The balance of the requirements will be met from Sceptre's corporate warranty supply, which is a pool of undedicated reserves in Alberta and Saskatchewan used by Sceptre to meet its corporate requirements. Sceptre believes this type of contract provides the buyer with access to significantly more gas reserves than would be available under a dedicated gas supply contract. Included in the corporate supply are reserves in the Crane Lake South gas field which Sceptre has received permission from certain working interest partners to market on their behalf. This permission may be revoked by the respective working interest partners upon one year's notice.

The contractual arrangements are discussed further in section 5.3.3 of these Reasons.

5.2.2 Reserves

Table 5-1 shows that the Board's estimate of Encogen's contracted remaining marketable gas reserves is 15 percent lower than Encogen's estimate but is 41 percent higher than the applied-for volume. The Encogen reserves are comprised of corporate warranty reserves and

Table 5-1

Comparison of Estimates of Encogen's Established Gas Reserves With the Applied-for Volume

10^6m^3 (Bcf)

	Encogen	NEB	Applied-for Volume
Dedicated Supply	1 246 (44)	1 218 (43)	
Net Corporate Supply	2 646 (93)	2 086 (73)	______
Total Supply	**3 892 (137)**	**3 304 (116)**	**2 327 (82)**

contractually dedicated reserves from Saskatchewan pools.

5.2.2.1 Net Corporate Warranty Supply

Table 5-2 shows a comparison between Sceptre's and the Board's estimates of Sceptre's total corporate supply and its net available corporate supply. Sceptre has existing and anticipated commitments besides the applied-for volumes.

The Encogen corporate gas supply at year-end 1988 consisted of proven and probable reserves in Alberta, Saskatchewan and British Columbia. Probable reserves have been discounted by a risk factor. Sceptre's estimate of reserves is 6 110 10^6m^3 (216 Bcf), whereas the Board's estimate is 5 579 10^6m^3 (197 Bcf).

The majority of the estimates of reserves for the corporate warranty supply pool were based on analysis conducted by a consulting firm for Sceptre. Sceptre has adopted this estimate of reserves as their corporate supply. The Board reviewed these estimates of reserves and found that, although there were variances in estimates for specific pools, in aggregate the Board's assessment of reserves corresponded very closely with that of Sceptre. The Board therefore has adopted Sceptre's estimate of reserves for this portion of the corporate supply pool.

For those pools for which Sceptre submitted its own estimates, the Board's estimate of reserves is generally somewhat lower. It is in these pools that most of the discrepancy in the estimates of corporate supply occurs. The variances are due largely to disagreement as to area assignment and net pay interpretation, but are also due to the cumulative effect of differences in several other reservoir parameters.

In addition to the estimates of reserves outlined above, Encogen submitted to the Board an overview of Sceptre's exploration plan for the upcoming five-year period which outlines plans to develop new gas reserves at a rate of approximately 1 000 10^6m^3 (35.3 Bcf) per year. Implementation of this plan in 1989 resulted in the addition of 538 10^6m^3 (19.0 Bcf), which is included in the table as 1989 exploration additions. The program highlighted 11 core areas for exploration, located mainly in Alberta, but it also included areas in British Columbia and Saskatchewan. Seven of the core areas are gas prone. The company plans to spend over $ 300 million to conduct drilling programs and develop reserves in these core areas. These estimates of undiscovered potential have not been explicitly accounted for in the Board's analysis but the Board recognizes that additional supply is likely to materialize from this ongoing program.

Sceptre has also obtained permission to market gas supply from its partners in the Crane Lake area of Hatton. This results in the addition of 1 190 10^6m^3 (42 Bcf) of gas supply, representing the partners' 37 percent working interest. The Board's estimate of these reserves is very similar to that of Sceptre.

Sceptre's estimate of the total corporate supply, including 1989 exploration additions and partner gas, is therefore 7 838 10^6m^3 (277 Bcf). The Board's estimate is slightly lower at 7 278 10^6m^3 (257 Bcf).

In addition to Encogen, this corporate supply must also supply 2 090 10^6m^3 (74.1 Bcf) to the Northland, Kirkland and Cochrane cogeneration plants in Ontario and 3 102 10^6m^3 (109.5 Bcf) to the Sceptre portion of NEP's export application . On the basis of Sceptre's estimates, the net corporate supply currently available to satisfy the Encogen commitment is 2 646 10^6m^3 (93.4 Bcf). The Board's analysis indicates that the net corporate supply available for Encogen is 2 086 10^6m^3 (73.6 Bcf).

Table 5-2

Comparison of Estimates of Sceptre's Corporate Warranty Supply and Net Corporate Supply Available for the Encogen Application

10^6m^3 (Bcf)

	Sceptre	**NEB**
Corporate Supply at 31 December 1988[1]	6 110 (216)	5 579 (197)
1989 Exploration Additions	538 (19)	538 (19)
Partner Gas[2]	1 190 (42)	1 161 (41)
Total Corporate Supply	**7 838 (277)**	**7 278 (257)**
Less: Northland, Kirkland and Cochrane Requirements[3]	2 090 (74)	2 090 (74)
NEP Requirements[4]	3 102 (110)	3 102 (110)
Net Corporate Supply Available For Encogen[5]	**2 646 (93)**	**2 086 (73)**

1. Comprised of corporate supply assessed by a consultant, additional pools submitted by Sceptre for which reserves estimates are based on in-house analysis and estimate of reserves for properties acquired from Oakwood (which are based on estimates at 1 November 1990).
2. Included in supply but not a firm contract, can be re-divided on one years notice.
3. Existing commitments which must be deducted to obtain corporate supply available for Encogen.
4. Sceptre's corporate supply has been submitted in support of both the NEP and Encogen applications. For presentation purposes, that portion of the corporate supply necessary to meet the requirement for the NEP application has been deducted in arriving at the net corporate supply available for Encogen.
5. Sceptre's available corporate supply reduced to account for supply commitments to other projects.

It is important to note that, for presentational purposes, the Board has allocated portions of the corporate supply to the respective projects. In fact, all of the requirements will be provided for by the total corporate supply.

The Board's analysis indicated that the corporate gas supply consists of 508 gas pools, the majority of which are not producing. Most of the pools are relatively small and are located in southern and central Alberta, mainly in Cretaceous sands. Eighty-two percent of the pools for which Encogen submitted reserves have reserves estimated by the Board to be less than $100\ 10^6 m^3$ (3.5 Bcf) of initial marketable gas.

5.2.2.2 Dedicated Supply

The dedicated reserves are located in the Saskatchewan Hatton and Crane Lake shallow gas reservoirs. The Hatton gas supply consists of proven reserves from fully developed lands. The Crane Lake gas supply consists of both proven and probable reserves, since the lands are not fully developed. Encogen has discounted the probable reserves by a risk factor.

The Board's estimate of reserves for the dedicated Saskatchewan supply is approximately the same as the Encogen estimate and consists of proven and probable reserves. The Board has also discounted the probable reserves by a risk factor. The small divergence in estimates of reserves is due to differences in interpretation of net pay.

In its analysis of the dedicated gas supply, the Board recognized three gas pools, all of which are producing. The pools are large and are located in southwestern Saskatchewan, in Cretaceous shallow gas reservoirs.

5.2.3 Productive Capacity

Encogen testified that approximately one-half of its requirements were to be provided by Sceptre from dedicated reserves in Saskatchewan. The balance of the requirements will be provided by Sceptre from its corporate warranty supply, a pool of undedicated reserves in Alberta and Saskatchewan used by Sceptre to meet its corporate requirements. The Board conducted separate analyses of the dedicated supply and the corporate warranty supply.

A comparison of the Board's and Encogen's estimates of productive capacity from the dedicated reserves with the corresponding portion of the applied-for requirements is shown in Figure 5.1. Encogen indicated that productive capacity from its dedicated reserves in Saskatchewan was expected to be adequate until 1997, but that increasing shortfalls were anticipated thereafter. The Board's projection of productive capacity from the dedicated reserves is very similar to that of Encogen and indicates shortfalls commencing in 1999.

A comparison of the Board's and Encogen's estimates of productive capacity from Sceptre's corporate warranty supply with Sceptre's total firm long-term gas sales is shown in Figure 5.2.

The Encogen estimate of productive capacity indicates adequate supply throughout the proposed licence term to meet requirements. Sceptre stated that its corporate gas strategy and contracting practices would prevent any shortfalls from occurring. Additionally, Sceptre stated that it had almost one million acres of undeveloped lands and a definitive five year exploration plan.

The Board's projection of productive capacity from the established reserves in Sceptre's corporate warranty supply shows that Sceptre's corporate requirements can be met until the year 2000, with increasing deficiencies thereafter. With the inclusion of the partner gas available to Sceptre, the Board estimates that requirements can be met until 2003.

5.3 Market and Commercial Arrangements and Regulatory Status

5.3.1 Market

The 62 MW Enserch Development Corporation ("Enserch") cogeneration plant will be located in Buffalo, New York. The thermal host is American Brass, a brass manufacturer and finisher which has occupied its current premises for 80 years. Niagara Mohawk, the power purchaser, provides electric service to residential, commercial and industrial customers in northern New York State including the cities of Albany, Buffalo, Syracuse and Watertown. The cogeneration plant is a

Figure 5.1

COMPARISON OF ESTIMATES OF ANNUAL PRODUCTIVE CAPACITY FOR ENCOGEN'S DEDICATED RESERVES IN SASKATCHEWAN

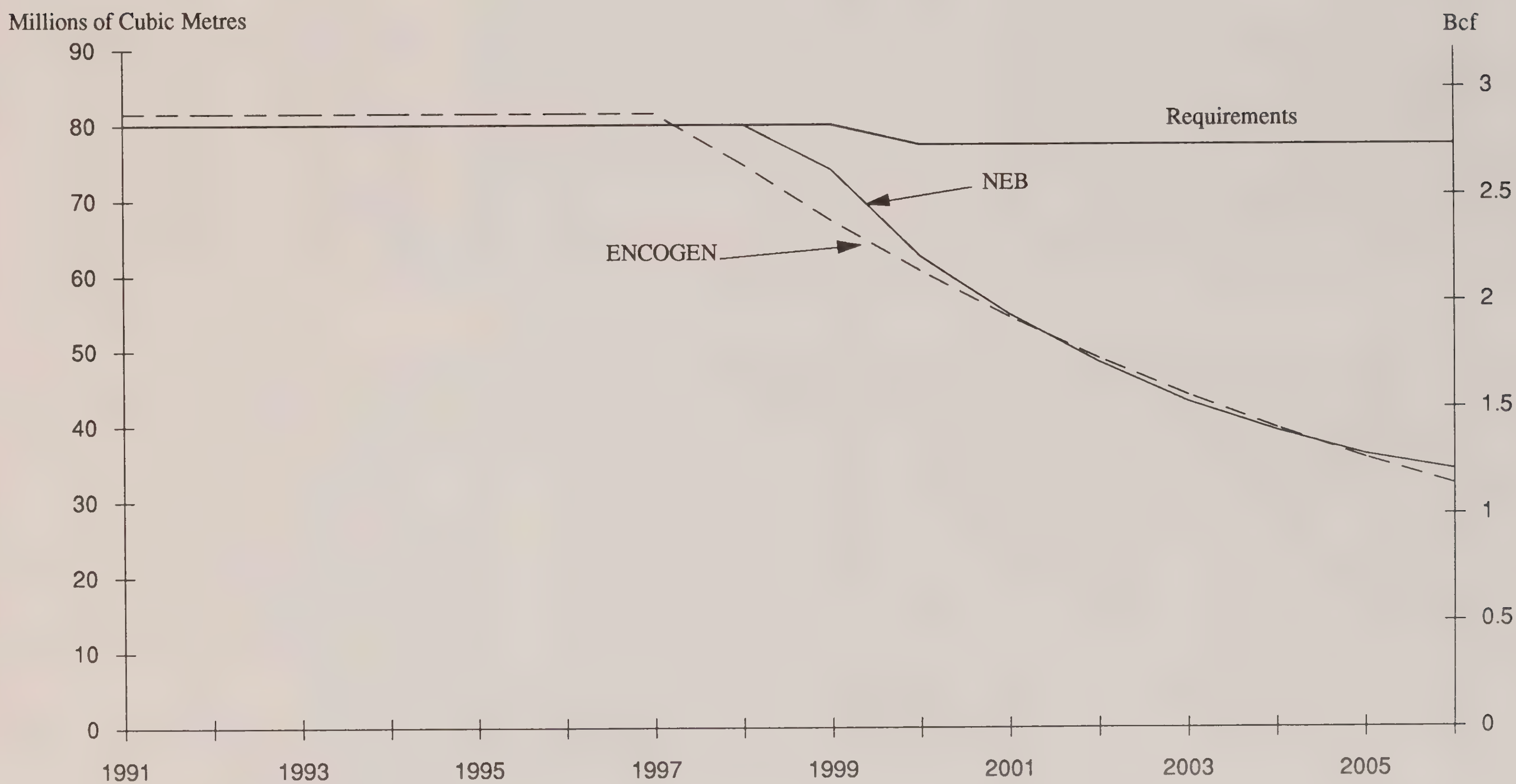
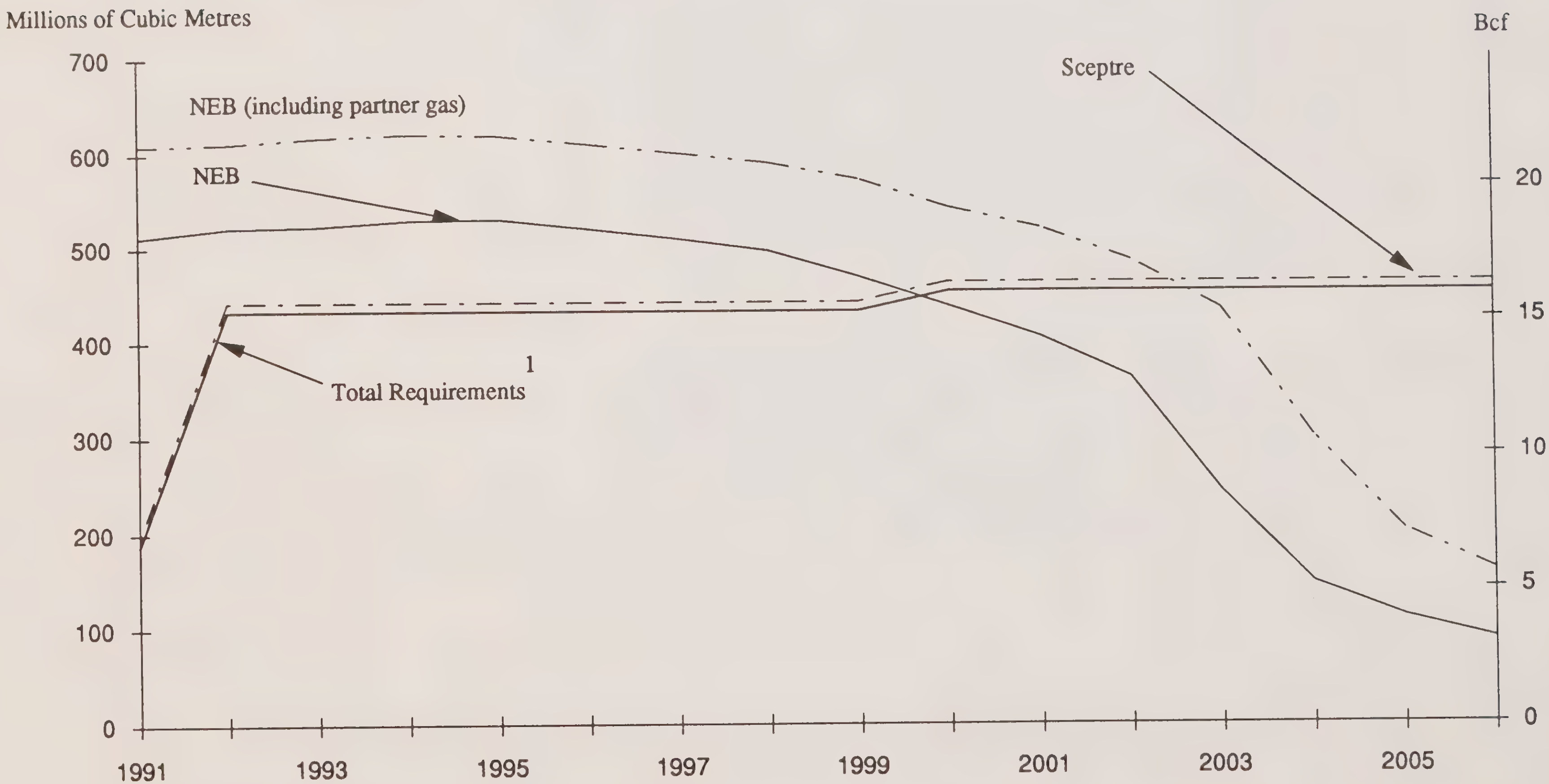


Figure 5.2

COMPARISON OF ESTIMATES OF ANNUAL PRODUCTIVE CAPACITY FOR SCEPTRE'S UNDEDICATED CORPORATE WARRANTY SUPPLY



1. Requirements include sales to Northland Power, NEP and Encogen.

must-run facility that is designed to generate approximately 488 000 MW.h of energy annually.

With respect to financing, Encogen has signed commitment letters with First National Bank of Chicago for a two year construction loan and a take-out loan equal to 85 percent of the construction loan when the construction loan expires. Closing for both loans was expected on or about 15 January 1991. The remaining 15 percent is likely to be assumed by one or more of three parties who have expressed interest in an equity position.

The Applicant testified that it would expect the load factor of the proposed export to be in the 92 to 95 percent range. This estimate was based on the facts that the cogeneration plant was a must-run facility, the contractual provisions requiring payment of a lump-sum and the obligation on the part of the buyer to pay all demand charges.

5.3.2 Transportation

The export volumes from Saskatchewan would be transported by TransGas to the points of connection with the TransCanada system. In Alberta, the gas would be delivered to Empress on the NOVA system. TransCanada would provide transportation from the TransGas and NOVA systems to the international boundary at Chippawa, Ontario. In addition to the incremental mainline facilities required on TransCanada to transport the volumes, there would also be a requirement for a new extension from Kirkwall to Chippawa, Ontario which is the subject matter of a separate TransCanada filing under section 58 of the Act and is referred to as the "Blackhorse Extension". This application is the subject of a separate hearing.

In the U.S., the gas would be transported by National Fuel Gas Supply Corporation ("National Fuel") on Empire to the facilities of National Distribution at Tonawanda, New York. National Distribution would, in turn, deliver the volumes to the cogeneration plant.

In Saskatchewan, Sceptre, through its subsidiary, Oakwood Petroleums Limited ("Oakwood"), has concluded firm transportation arrangements with TransGas under an agreement dated 19 May 1989 to deliver the proposed export volumes to the TransCanada system. The agreement is for a term of five years and Oakwood has the right to continue the contract. Sceptre stated that it would not require additional transportation from NOVA to accommodate the volumes of gas to be delivered from Alberta sources of supply. Encogen has executed a precedent agreement with TransCanada dated 20 December 1989, as amended on 23 April 1990 and 19 October 1990 to transport the gas from the interconnections with the TransGas and NOVA systems, to Chippawa. The parties have also concluded a performance agreement on financial assurances dated 12 April 1990.

In the U.S., Encogen has signed a precedent agreement dated 31 October 1990 with National Fuel and Empire under which Empire has agreed to transport the gas on National Fuel's behalf on its proposed facilities from the international border to a proposed point of interconnection with the facilities of National Distribution. EDC Four, Inc. ("EDC") and National Distribution have an executed precedent agreement dated 28 November 1989 for the transportation of the gas from Tonawanda to the cogeneration facility. The National Distribution system would require additional facilities which are expected to be available in November 1991.

5.3.3 Gas Sales Contract

Encogen's executed gas purchase contract with Sceptre provides for a daily quantity of 15 10^3m^3 (0.5 MMcf) plus a volume to meet the fuel and shrinkage requirements on the TransCanada system.

The arrangement includes a number of conditions precedent. Sceptre is responsible for obtaining provincial removal permits and for arranging transportation within Saskatchewan and Alberta. Encogen has responsibility for securing an export licence and all regulatory authorizations in the U.S., and for arranging transportation on TransCanada and on pipelines in the U.S. With respect to the financing of the project, both Sceptre and Encogen have the right to cancel the contract if Encogen fails to secure financing within one year from the date that all approvals have been obtained.

As part of the agreement, Encogen is committed to make a lump-sum payment of $ U.S. 1.5 million to Sceptre when all approvals and conditions have been met and financing for the cogeneration plant has been arranged. The contract also contains a provision under which, if Sceptre fails to deliver gas to Encogen during the first five years in accordance with the terms of the gas purchase agreement, Sceptre would be obligated to refund to Encogen $ U.S. 25 thousand for each month during which the failure occurs.

The gas purchase agreement will become effective as early as 1 November 1991 and as late as 30 June 1994 depending on certain events specified in the contract. If the agreement has not become operational by mid-1994, either party has the right to terminate the contract on seven days notice. The arrangement is for a primary term of 15 years from the date of commencement of gas deliveries. It will continue to operate thereafter on an annual basis until either party elects to cancel the contract on 60 days notice.

While there is no take-or-pay provision included in the agreement, Encogen is committed, under normal operating circumstances, to take gas from Sceptre and self-displacement is not permitted. In the event that Encogen faced a curtailment to the volume that it expected to purchase, the company would negotiate with Sceptre to change the deliverability obligations of the contract.

Under the pricing provisions of the agreement, while Sceptre is responsible for obtaining and maintaining the transportation contracts with TransGas and NOVA, Encogen will reimburse Sceptre for the actual costs incurred. Reflecting the original intent to supply all of the gas required for the project from Saskatchewan reserves, the arrangement contains a condition that NOVA costs do not exceed those of TransGas. Encogen is also responsible for paying the transportation on TransCanada from western Canada to the international border at Chippawa and for the transportation in the U.S.

The commodity charges to be paid by Encogen to Sceptre are established for the 15-year primary term of the agreement. For gas sold in the period up to and including 31 December 1992, the price will be $ U.S. 1.53/GJ ($ U.S. 1.65/MMBtu). By the year 2000, it will have increased to $ U.S. 3.28/GJ ($ U.S. 3.54/MMBtu) and, by 2009, to $ U.S. 5.82/GJ ($ U.S. 6.26/MMBtu).

The fixed prices under the gas purchase agreement were negotiated to correspond with Encogen's power sales arrangement with Niagara Mohawk. Because the cogeneration facility will be project-financed, Encogen believed that it was prudent to minimize risk by having its natural gas costs, which are the single largest operating expense, track the guaranteed future revenue stream from the sale of electricity to Niagara Mohawk. Encogen stated that, prior to concluding the agreement, Sceptre had undertaken its own assessment of future gas prices and that the fixed price structure would ensure an acceptable price to Sceptre over the life of the contract.

The agreement provides for arbitration of any disagreement arising from the contract, with the written consent of both Encogen and Sceptre.

5.3.4 Power Sales Agreement

The proposed sale of electricity from the cogeneration plant, a QF facility that is expected to be in commercial operation in March 1992, will be pursuant to the power sale agreement dated 18 February 1988, as amended, between American Brass and Niagara Mohawk. In an agreement dated 28 February 1989, American Brass assigned its title in the power sale agreement to EDC. The agreement will continue for a period of 25 years from the initial operation date and includes automatic one year renewals until termination by either party.

The agreement includes peak and off-peak pricing provisions. The cost of electricity to be purchased by Niagara Mohawk is to be equal to or below Niagara Mohawk's avoided cost. Pricing is separated into three time periods, and includes an adjustment account. During period one, prices are $ 0.06/kW.h. During periods two and three, prices are equal to 95 and 90 percent of Niagara Mohawk's avoided costs, as determined by the NYSPSC. The first period starts at the commercial operation date until the balance in the adjustment account reaches zero. The second period, if any, is the period from the end of the first period to the end of year fifteen. The third period, if any, consists of the period from the end of the second period to the end of year 25. The

sale of electricity from the American Brass facility does not require wheeling by third parties.

Niagara Mohawk and EDC entered into a third amendment to the agreement dated 25 April 1990, which includes a provision allowing Niagara Mohawk to curtail power purchases for up to 1,700 hours annually. The NYSPSC in its Case 88-E-081 had rejected curtailment clauses that had been included in New York State utility power contracts. However, the NYSPSC in a further Order clarified its Order in Case 88-E-081 to ensure utilities were accorded their federal rights to curtail purchases from QF's, due to operational circumstances, which would result in costs greater than those a utility would incur if it did not make such purchases. The utilities were told they could include curtailment language in future contracts, which comports with NYSPSC Orders, but that they could not expand upon the curtailment presumptions established by the NYSPSC. The 25 April 1990 amending agreement has received NYSPSC approval.

5.3.5 Thermal Energy Sales Agreement

The proposed sale of thermal energy to American Brass will be pursuant to the thermal energy sales agreement dated 17 January 1989, between EDC and American Brass. The agreement will continue for a period of 25 years from the date of commercial operation of the project. The agreement is subject to a five-year extension upon mutual agreement by the parties. American Brass is obligated to purchase sufficient thermal energy so that the cogeneration plant will maintain its QF status. Should American Brass default on its steam purchase obligations, the agreement provides for continuing access to the cogeneration plant to allow continued operation and to provide methods and routes of interconnection with other purchasers of cogenerated thermal energy or electrical energy. A back-up glycol heating system is required to ensure American Brass with secure thermal energy. The agreement also provides compensation to EDC if American Brass should withdraw from the agreement.

5.3.6 Regulatory Status

Sceptre applied to the Saskatchewan Department of Energy and Mines ("Saskatchewan") on 26 April 1989 for a gas removal permit. By a letter dated 26 November 1990 Saskatchewan stated that it was satisfied that Sceptre had secured sufficient reserves and deliverability to meet the requirements for a gas removal permit and that an authorization would be issued following the completion of downstream transportation and regulatory requirements. This permit would allow Sceptre to remove 2 327 10^6m^3 (82.1 Bcf) from Saskatchewan over a 15-year period.

Sceptre has filed notice with the AERCB of its intent to file an application for an Alberta removal permit. This notice was acknowledged by the AERCB. Sceptre was awaiting the Saskatchewan decision before it made further submissions to the AERCB but Sceptre stated that it would be applying for the full daily volume to allow it to move gas from either Alberta or Saskatchewan and it expected that the term volume would be the difference between what is approved in Saskatchewan and what is required for the project.

Encogen applied to the U.S. DOE/FE for import authorization on 23 February 1990.

The cogeneration facility has obtained FERC QF status.

5.4 Views of the Board

The Board's analysis of Encogen's supply attempted to identify the key components of both the dedicated and undedicated supply upon which a decision as to the adequacy of supply could be made.

In assessing the adequacy of reserves relative to the Encogen requirements, the Northland sales and NEP requirements were deducted from the available undedicated reserves. The sum of the remainder of the available undedicated reserves and the dedicated reserves was then compared to the Encogen applied-for requirements. Adopting this approach, a minor deficiency in reserves relative to the applied-for term volume exists. The partner gas available to Sceptre alleviates

this deficiency, but the Board notes that the partner gas agreements can be terminated upon one year's notice and the Board therefore does not consider these reserves to be a firm long-term supply source. The continued availability of these reserves will be dependant upon the willingness of the partners to continue to have Sceptre market the gas in the future.

For presentationl purposes, the Board assessed the adequacy of Encogen's reserves relative to requirements by allocating reserves to specific requirements. The Board recognizes that in fact the total requirements will be met by the total corporate warranty supply pool. The Board's assessment of productive capacity for the corporate warranty supply is based on this premise.

The Board's analysis of productive capacity available to support the proposed export showed increasing deficiencies after 1998 for the dedicated reserves, and beyond 2000 to 2003 for the corporate warranty supply. An increased dependence upon Sceptre's exploration lands will be required to provide productive capacity sufficient to meet requirements in the latter years of the proposed export term.

In its analysis of Sceptre's corporate warranty supply, the Board did not account for potential reserves additions that would result from Sceptre's five year exploration plan. Sceptre provided considerable data regarding its exploration plans at the hearing, and the Board is satisfied that Sceptre will be able to rely on its ongoing exploration program to satisfy a portion of its requirements over the latter part of the proposed licence term.

The Board is satisfied with the downstream markets for the electricity and steam produced by the cogeneration facility and that the facility would operate at a high load factor. The Board notes that DOE/FE import authorization has not yet been received but does not consider this to be a major impediment. The Board notes that project financing and FERC QF certification have been received, and that the cogeneration facility was expected to be completed and in operation by March 1992.

The Board also notes that transportation has been arranged on all required pipelines and that Encogen is responsible for all transportation charges on the TransCanada and TransGas systems and on NOVA to the extent that they are not in excess of costs that would have been incurred if the gas had been delivered on the TransGas system. As a result, the Board is satisfied that there will be recovery of fixed transportation costs in Canada.

The price of the gas to be exported was negotiated between Encogen and Sceptre, having regard to the provisions of the power sale agreement with Niagara Mohawk which provides for a guaranteed revenue stream which, in turn, enabled Encogen and Sceptre to negotiate a guaranteed gas price over the term of the contract.

On the basis of the pricing provisions of the power sale agreement and the provision in the gas purchase contract for Encogen to make a lump sum payment of $ U.S. 1.5 million to Sceptre and the recovery of transportation costs in Canada, the Board is of the view that the proposed export will operate at a high load factor which would ensure a high level of take under the contract.

The Board has reviewed the gas sales contracts and has noted that they have been negotiated at arm's length.

Producer support is evidenced by the fact that Sceptre, the gas supplier, has executed a gas purchase contract with Encogen.

5.5 Decision

The Board has decided to issue a gas export licence to Encogen, subject to the approval of the Governor in Council. Appendix IV contains the terms and conditions of the licence, including a condition that the term of the licence shall commence on 1 November 1991 or as soon thereafter as gas can be made available and shall end on 1 November 1993, unless exports have commenced under the licence on or before 1 November 1993, in which case the term would end on 31 October 2006.

Chapter 6

Esso Resources Canada Limited

6.1 Application Summary

By application dated 27 July 1989, as amended, Esso applied under Part VI of the Act for a natural gas export licence with the following terms and conditions:

Term	- from 1 November 1991 for a term of 15 years	
Point of Export	- near Iroquois, Ontario.	
Maximum Daily Quantity	- 992 10^3m^3	(35.0 MMcf)
Maximum Annual Quantity	- 362 10^6m^3	(12.8 Bcf)
Maximum Term Quantity	- 5 432 10^6m^3	(191.8 Bcf)
Tolerances	- 10 percent per day and 2 percent per year	

The gas proposed for export would be drawn from existing pools in Alberta controlled by Esso and from reserves Esso has under contract with other Alberta producers.

NOVA would deliver the gas to TransCanada at Empress, Alberta and TransCanada would transport the gas to the export point near Iroquois, Ontario. The gas would then be transported on the IGTS, Tennessee and Algonquin Gas Transmission Company ("Algonquin") systems for delivery to Boston Gas Company ("BGC").

The gas would be used by BGC, an LDC, for system supply.

6.2 Gas Supply

6.2.1 Supply Contracts

Esso intends to supply most of the gas for the proposed export from its own pools. The Board notes that no specific pools have been contractually dedicated to the export, but Esso submitted a list of uncontracted pools from which it intends to provide the required volume.

In addition, Esso has executed four gas supply contracts of various terms with the following six producers: Hillcrest Resources Ltd., Novalta Resources Ltd., Petrorep (Canada) Ltd. and an aggregated group of Shunda Energy Corporation, Northern Development Company Limited and Wintershall Oil of Canada Limited. Each of the four contracts has provisions to provide a specific portion of Esso's overall DCQ. The natural gas reserves subject to these contracts are not dedicated to a specific market and the producers have consented to allow Esso to sell to any market it chooses. These contracts will supply approximately 14 percent of the volume required for the export.

6.2.2 Reserves

Esso and the above producers used AERCB estimates of reserves for their pools and, in cases where less than 100 percent of the pool was owned by Esso or its six producers, applied appropriate ownership percentages to determine net reserves from the AERCB estimates. Table 6-1 shows that the Board's estimate of Esso's reserves is approximately seven percent lower than Esso's estimate but is 21 percent higher than the applied-for volume.

The discrepancy in estimates of reserves arises predominantly from differences in the Board's and Esso's estimates of reserves for several large Viking gas pools. Esso's adopted estimates of reserves are based largely on volumetric studies. The Board's estimates of reserves for these Viking pools are based on geological studies but also reflect recent studies of pool performance and well drainage. The results of this analysis indicated the Viking reserves in the Redwater and Westlock fields to be smaller than previously anticipated. The remaining divergence in estimates of reserves

Table 6-1

Comparison of Estimates of Esso's Established Gas Reserves With the Applied-for Volume

10^6m^3 (Bcf)

Esso[1]	NEB[2]	Applied-for Volume
7 038 (248)	6 549 (231)	5 432 (192)

1. as of November 1989 (Revisions noted in written evidence).
2. As of 31 December 1988.

arises primarily from the cumulative effect of small differences for individual pools.

The Board's analysis indicated that Esso's gas supply is contained in 190 pools, all of which are in Alberta. These pools are distributed throughout the province and include most of the significant producing zones, although the majority of the pools are concentrated in Cretaceous zones. Sixty-nine percent of the pools for which Esso submitted estimates of reserves have reserves estimated by the Board to be less than 100 10^6m^3 (3.5 Bcf) of initial marketable gas. However, a significant portion of the net remaining reserves (19 percent) are found in pools whose initial marketable reserves are estimated to be larger than 3 000 10^6m^3 (106 Bcf).

The Board's estimate of reserves is somewhat lower than that of Esso, primarily due to disagreement as to the assessment of reserves for certain Viking pools. However, the Board's estimate of reserves exceeds the applied-for volume by a substantial amount.

6.2.3 Productive Capacity

A comparison of the Board's and Esso's projections of productive capacity with the applied-for requirements is shown in Figure 6.1.

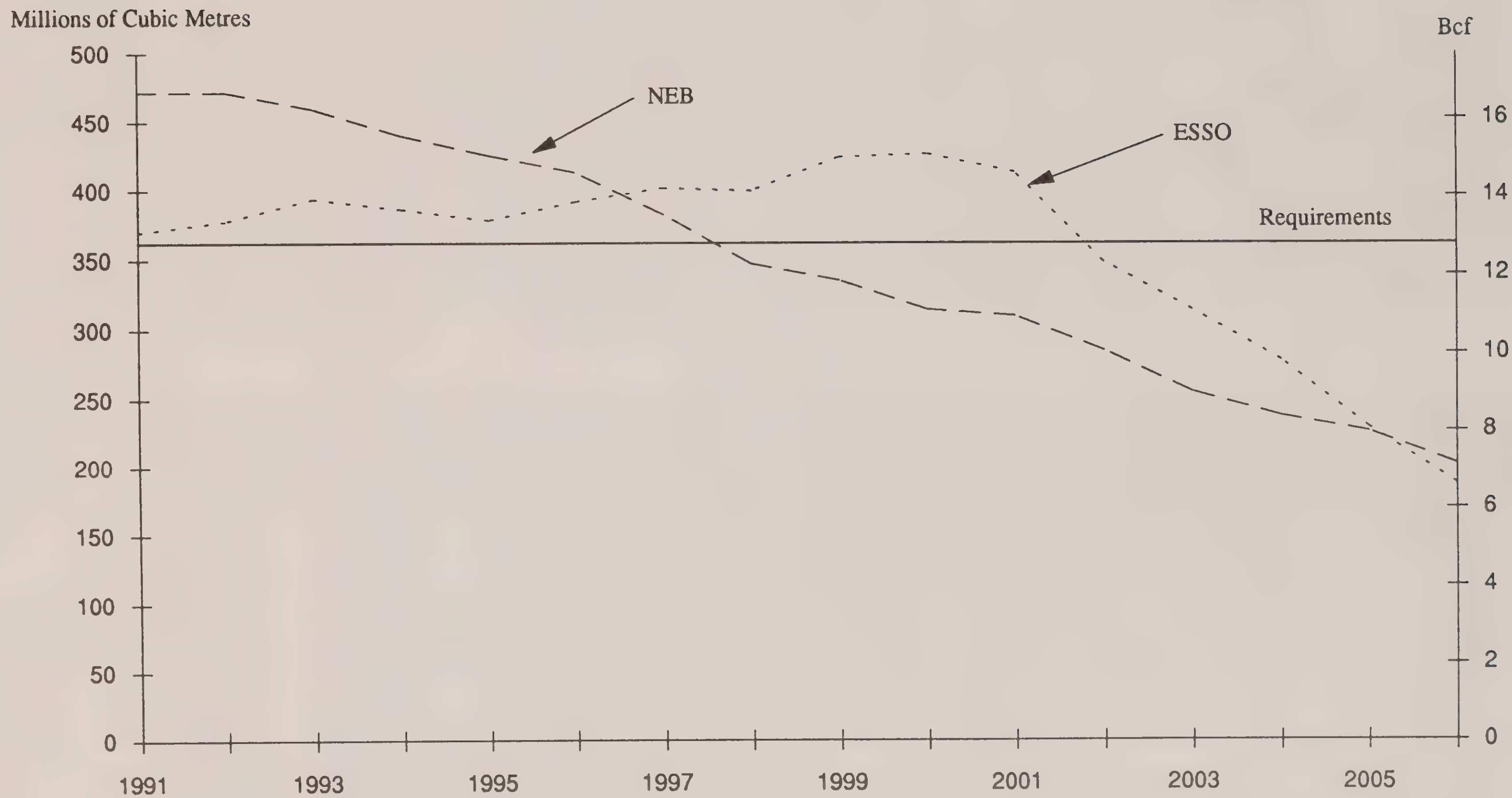
Esso's projection of productive capacity from the reserves associated with this project indicated a deficiency in supply relative to requirements after the year 2002. However, Esso submitted that these reserves were expected to be capable of substantially more than the indicated deliverability. Esso also suggested that minor deliverability shortfalls could be remedied by additional deliverability from reserves appreciation and by advancing the pace of development for certain of the pools.

The Board's projection of productive capacity for the specific reserves included in the application indicates shortfalls in productive capacity commencing in the year 1998.

In addition to the specific reserves submitted in its application, Esso provided detailed information on its overall corporate supply/demand situation. Esso stated that, on a corporate basis, it has a surplus of supply relative to requirements throughout the term of the proposed export

Figure 6.1

COMPARISON OF ESTIMATES OF ANNUAL PRODUCTIVE CAPACITY FOR ESSO



licence and that it could rely on its corporate gas supply to alleviate minor deliverability shortfalls.

6.3 Market and Commercial Arrangements and Regulatory Status

6.3.1 Market

The gas proposed for export would be used as system supply by BGC for use by its customers in the City of Boston and 73 other cities and towns in eastern Massachusetts. BGC has been in business since 1824 and is the largest LDC in New England, serving over 460,000 residential and 36,000 industrial and commercial customers.

BGC intends to diversify its sources of supply, meet increasing demand from traditional and non-traditional markets, and to reduce reliance on other more expensive and less reliable sources by contracting for 1 476 $10^3m^3/d$ (52.1 MMcfd) of Canadian gas. The applied-for Esso volumes would comprise 991 $10^3m^3/d$ (35.0 MMcfd) of that total and would represent less than 11 percent of BGC's total annual purchases. BGC stated that it had been in a position of undersupply for a number of years.

BGC currently purchases and distributes approximately 3 000 10^6m^3 (99.8 Bcf) of natural gas per year. The majority of this gas is obtained from two major U.S. transmission companies on a long-term firm basis. In the 1988-89 contract year, BGC had contracted volumes of 8 784 $10^3m^3/d$ (310.0 MMcfd) from Algonquin and Tennessee, which included 303 $10^3m^3/d$ (10.7 MMcfd) of Canadian gas purchased from Boundary Gas Inc.

BGC contracts with its pipeline suppliers and others for storage and transportation of gas from underground storage fields. Pipeline storage of 1 594 $10^3m^3/d$ (56.3 MMcfd) was available in 1988-89.

BGC owns or leases facilities which allow it to store liquefied natural gas ("LNG"). LNG storage provides more than 113 10^6m^3 (4.0 Bcf) of gas available for use during extremely cold winter weather.

BGC also owns and operates a substitute natural gas facility. The facility utilizes propane as its feedstock and can produce up to 1 133 $10^3m^3/d$ (40.1 MMcfd). In addition, propane mixed with air at plants located in BGC's service territory can produce up to 3 116 $10^3m^3/d$ (110.0 MMcfd) of natural gas supplement.

Precedent agreements for 1 122 $10^3m^3/d$ (39.6 MMcfd) of U.S.-sourced NOREX volumes to be transported on Tennessee and for 822 $10^3m^3/d$ (29.0 MMcfd) of Penn East-CDS/Algonquin gas have also recently been executed.

Turning to BGC's requirements, BGC stated that cogeneration and gas air conditioning appear to offer significant market opportunity over the next several years. BGC is also aggressively pursuing several large power production and cogeneration opportunities both within and outside its service territory. However, the volumes proposed for export will not be targeted to any particular sector, but will be used for general system supply.

In 1989, BGC's total end-use markets consumed 70.8 PJ (67.1 million MMBtu) of gas. BGC's residential market segment is anticipated to increase from 42.4 PJ (40.2 million MMBtu) in 1989 to 44.5 PJ (42.2 million MMBtu) at the end of the contract term. The commercial/industrial market segment, which includes building heating and air conditioning for apartment houses and miscellaneous lighting and other contracts, is expected to increase from 28.4 PJ (26.9 million MMBtu) in 1989 to 51.0 PJ (48.4 million MMBtu) in 2006. BGC expects that its cogeneration market will start taking gas in 1993. The large cogeneration market is forecast to consume 15.8 PJ (15.0 million MMBtu) in that year, to increase to 24.2 PJ (22.9 million MMBtu) in 1994 and then to remain constant at the 1994 level for the remainder of the forecast period. BGC projects that the total energy demand of its end-use markets would increase to 119.8 PJ (113.6 million MMBtu) by the year 2006.

Supply volumes exceeding firm requirements are made available for sale to BGC's interruptible market. This market can consume up to 9 915 $10^3m^3/d$ (350 MMcfd).

BGC anticipates that the gas proposed for export would be taken at a 95 percent load factor. BGC's forecast is based upon its long-range gas sendout

model which simulates BGC's purchasing practices.

6.3.2 *Transportation*

The gas would be transported within Alberta by NOVA to Empress and from Empress to the export point near Iroquois, Ontario by TransCanada. The gas would then be delivered by IGTS to the Tennessee system. Tennessee would deliver part of the volume directly to BGC with the remainder being transported through the Algonquin system for final delivery.

Firm transportation on NOVA has been arranged by Esso commencing in the 1991/1992 contract year for the full volume of gas proposed for export.

Esso and TransCanada entered into a precedent agreement dated 1 May 1989, as amended, for firm transportation of the full export volume. The service term would commence no earlier than 1 November 1991 and end on 31 October 2006. Esso is thus responsible for demand charges on TransCanada.

BGC entered into precedent agreements dated 16 December 1988, 11 October 1989, and 13 January 1989 with IGTS, Tennessee, and Algonquin respectively for firm transportation.

Existing capacity on Tennessee would be used to deliver the gas to Algonquin through existing facilities. Tennessee would, however, require expansion of some of its other facilities. Algonquin would require additional facilities for delivery of the gas to BGC. In each case the necessary applications have been made to the FERC.

6.3.3 *Gas Sales Contract*

A contract dated 1 May 1989, as amended, has been executed by Esso and BGC. The contract term extends for 15 years from the commencement of firm deliveries and may be further extended by up to ten years.

The contract provides for the daily delivery of up to 992 $10^3 m^3$ (35.0 MMcf) of gas at the IGTS inlet. Provision is also made for the delivery of interruptible volumes prior to firm transportation service being available.

The contract is subject to several conditions precedent, including receipt of all Canadian and U.S. regulatory approvals and finalization of all Canadian and U.S. transportation arrangements. If all conditions precedent are not satisfied or if gas is not capable of flowing due to transportation problems by 31 December 1992, the contract may be terminated. The contract may also be terminated if, following the second year, a governmental or regulatory agency issues any decision or takes any action which can be deemed to have an adverse impact. This clause was included in an attempt to discourage any regulatory intervention which might have an adverse impact on the operation of competitive market forces.

Should BGC, for reasons other than force majeure, take less than 75 percent of the MDQ, then Esso may reduce the MDQ to the level of the average daily nominations over that period. Further, should BGC take less than 75 percent of the MDQ in any given calendar quarter for reasons other than force majeure, then it must make a deficiency payment to Esso. The payment is calculated as the difference between actual nominations and 75 percent of the MDQ multiplied by 20 percent of the applicable average commodity charge. Should less than the full MDQ be nominated on any day, then Esso has the right to use BGC's unutilized transportation capacity to market such gas itself.

The price paid by BGC for gas purchased from Esso will consist of a commodity charge component and a demand charge component. The commodity charge will be a function of a 1988 base price of \$ U.S. 1.35/GJ (\$ U.S. 1.45/MMBtu) indexed monthly to the Massachusetts Market Weighted Average Price Index. This index consists of a basket of weighted average fuel prices currently including No. 2 fuel oil in Boston, No. 6 spot fuel oil in New York, and natural gas. The natural gas price is taken to be the gas cost component of Tennessee and Texas Eastern Transmission Corporation's ("Tetco") commodity charges.

The estimated price that would have occurred under the terms of this contract at the Alberta border as of January 1990 was \$ Cdn. 2.69/GJ (\$ Cdn. 2.89/MMBtu).

The commodity charge and escalation mechanism related thereto may be re-opened every three years with provision for arbitration. Arbitration is intended to yield a commodity charge competitive with other long-term firm contracts in Massachusetts.

The demand charge includes all fixed and variable transportation charges paid by Esso for transportation of the gas in Canada plus a fuel gas component and any taxes levied on transportation service or fuel gas.

6.3.4 Regulatory Status

Esso received AERCB removal permit GR 90-4 on 13 February 1990 authorizing the removal of 6 030 10^6m^3 (213 Bcf) of natural gas from Alberta over a 15-year term commencing 1 November 1991.

An application for DOE/FE import authorization was made 20 June 1989. It was stated in final argument that an order was anticipated in the near future.

BGC also applied for and received approval of the gas sales contract from the Massachusetts Department of Public Utilities.

6.4 Views of the Board

The Board is satisfied as to the adequacy of Esso's supply to meet the proposed export. Although Esso's evidence on the specific pools associated with this project indicates that a shortfall in productive capacity will occur in the latter part of the proposed licence term, the Board recognizes that Esso could rely on its corporate gas supply to remedy potential deficiencies in supply.

The Board is satisfied that the LDC market of BGC represents a stable long-term market for Canadian gas. Esso's sales would represent less than 11 percent of BGC's total annual purchases and, therefore, it is unlikely that changes in the LDC's overall demand would be reflected wholly upon the sales by Esso.

The Board notes that transportation has been arranged on all required pipelines and is satisfied that the demand charge component of the gas sales contract's pricing structure would ensure recovery of all fixed Canadian transportation costs.

The Board believes that the contractual provisions regarding deficiency payments and the right of Esso to reduce the MDQ plus BGC's obligation to pay demand charges regardless of takes will assure that gas is taken under the contract at a high level.

The Board has reviewed the gas contract and has noted that it has been negotiated at arm's length.

Esso has endorsed the proposed export by virtue of having executed a gas contract with BGC. The Board notes that the six producers with which Esso has supply contracts have consented to any present or future sale.

6.5 Decision

The Board has decided to issue a gas export licence to Esso, subject to the approval of the Governor in Council. Appendix IV contains the terms and conditions of the licence, including a condition that the term of the licence shall commence on 1 November 1991 and shall end on 1 November 1993, unless exports have commenced under the licence on or before 1 November 1993, in which case the term would end on 31 October 2006.

Chapter 7

FSC Resources Limited

7.1 Application Summary

By application dated 30 November 1989, as amended, FSC sought, pursuant to Part VI of the Act, a new natural gas export licence with the following terms and conditions:

Term	- 1 November 1991, for a period of 15 years
Point of Export	- near Niagara Falls, Ontario
Maximum Daily Quantity	- 453 10^3m^3 (16.0 MMcf)
Maximum Annual Quantity	- 165 10^6m^3 (5.8 Bcf)
Maximum Term Quantity	- 2 480 10^6m^3 (87.6 Bcf)
Tolerances	- 10 percent per day and 2 percent per year.

The proposed export volumes would be produced from fields within the province of Alberta and supplied by WGML from TransCanada's contracted reserves. The gas would be transported on the NOVA system by WGML to the point of interconnection with TransCanada at Empress, Alberta. FSC, a subsidiary of Falcon Seaboard Resources Inc. ("Falcon Resources"), would take possession of the gas at Empress where it would be transported through TransCanada's system to the international border near Niagara Falls, Ontario. The gas would be sold to Falcon Seaboard Gas Company ("Falcon Gas"), a subsidiary of Falcon Resources, at the international border. In the U.S., National Fuel would provide transportation to a cogeneration facility to be constructed in North East, Pennsylvania and owned by Northern Consolidated Power, Inc. ("NorCon"), also a subsidiary of Falcon Resources. The plant is designed to produce 79 MW of electricity which will be sold to Niagara Mohawk. Welch Foods Inc., ("Welch") a cooperative would purchase the steam. The cogeneration facility would be located at the Welch plant site on land leased from Welch.

7.2 Gas Supply

7.2.1 Supply Contracts

FSC has executed a 15-year gas supply contract with WGML to purchase up to 453 10^3m^3/d (16 MMcfd) of natural gas. WGML will obtain the necessary gas supply for this contract through numerous purchase agreements with TransCanada. The FSC contract is similar to, and includes the same supply assurances as other WGML long-term gas supply contracts. The supply assurances include WGML's obligation to maintain a remaining reserves-to-production ratio ("RR/P") above ten. Should the RR/P ratio fall below ten, WGML will be precluded from entering into new sales contracts, including renewal of existing contracts. Additionally, in times of a constraint on WGML's gas supply, FSC and other long-term customers would have priority over short-term contracts for the available gas supply. In this regard, WGML is contractually obliged to curtail short-term sales before it restricts gas supplies to its long-term sales (i.e. greater than ten years).

The supply contract with WGML provides FSC with the option to reduce its DCQ in return for a penalty/compensation payment to WGML. This option, referred to as the "buy-down" provision, is exercisable at any date prior to the initial delivery date in the WGML contract and on the second and fourth anniversaries of the initial delivery date. The magnitude of the payment is related both to the volume substituted and the contractual pricing provisions.

FSC stated that the purpose of the buy-down provision was to protect and improve project economics. The provision provides FSC with the protection that if it became uncomfortable with the WGML gas supply, it could arrange for substitute supplies. FSC indicated that it was probable that a portion of the WGML supply would be decontracted prior to initial delivery;

that it would also pursue the decontracting option during operation of the WGML contract; that FSC was in active negotiations for alternate supplies; that, if alternate supplies were arranged, any of the terms and conditions, including price, might differ from those in the WGML contract; and that alternate supplies could include U.S.-sourced natural gas.

FSC indicated it expected to have its supply arrangements made firm by the first quarter of 1991, prior to finalizing financing for the cogeneration plant.

7.2.2 Reserves and Productive Capacity

Please refer to section 17.2 of these Reasons for Decisions for information on WGML's gas supply, upon which FSC is relying.

7.3 Market and Commercial Arrangements and Regulatory Status

7.3.1 Market

The export volumes would be used to fuel a 79 MW cogeneration facility to be constructed in North East, Pennsylvania at the Welch plant. Financing for the cogeneration facility is expected to be in place by March 1991 with construction slated to begin in April 1991. The facility is expected to be in-service by the spring of 1992. The natural gas would be sold by FSC to Falcon Gas for resale to NorCon, the owner and operator of the proposed cogeneration plant. The applied-for volumes would represent 100 percent of the plant's natural gas requirements.

FSC indicated that NorCon would purchase gas on a short-term basis until 1 November 1992 when the transportation facilities for the proposed export volumes are expected to be available. FSC indicated that there appeared to be no difficulties in arranging transportation on U.S. pipelines for the interim period.

FSC has forecast a 95 percent load factor for the cogeneration facility. It pointed out that because of the demand/commodity pricing structure of the contracts, NorCon would have an incentive to take the gas at a high load factor in order to reduce the per unit cost of the gas. FSC stated that the manufacturers of the gas turbines suggest that scheduled outages for routine maintenance will be about two percent. FSC added that, based on its experience with the company's plant in Texas, unscheduled outages will be approximately three percent.

The thermal host, Welch, is a cooperative that will utilize the steam output from the cogeneration facility for heating and processing needs and to operate an absorption refrigeration unit. In addition, NorCon will provide Welch with electricity. The direct sale of electricity to Welch occurs because the Welch plant is not synchronized with Pennsylvania Electric. The direct sale avoids the need for two electrical grids in the Welch plant. Pennsylvania Electric, the franchisee in whose area Welch is located, concurs with this direct sale of electrical energy.

Niagara Mohawk, the power purchaser, is a New York State utility which provides electrical service to residential, commercial and industrial customers in New York State. Its four major markets are the cities of Albany, Buffalo, Syracuse, and Watertown. The cogeneration plant, a must-run facility, is designed to generate approximately 640,000 MW.h of electricity annually.

7.3.2 Transportation

The proposed export volumes would be transported to the Alberta/Saskatchewan border, at Empress, on the NOVA system. From Empress, the gas would be delivered by TransCanada to the international border at Niagara Falls, Ontario. In the U.S., National Fuel would provide transportation to the cogeneration plant in North East, Pennsylvania where North East Heat & Light would operate a meter station to measure the gas.

Within Alberta, transportation would be provided pursuant to WGML's existing, long-term firm capacity on the NOVA system. No incremental facilities would be required. The arrangements for the transportation of the gas from Empress to Niagara Falls beginning on 1 November 1991 were the subject of an application by FSC under section 71 of the NEB Act. Upon notification by

National Fuel that it intended to file an application with FERC by the fall of 1991 for the remaining facilities required to transport the Falcon Gas volumes, FSC withdrew the section 71 application. FSC has a precedent agreement dated 13 November 1990 with TransCanada for firm service beginning 1 November 1992. TransCanada will be making application to the Board for the facilities required to transport gas for this project and other projects in a subsequent facilities application.

In the U.S., Falcon Gas has entered into a precedent agreement dated 3 November 1989 with National Fuel for the transportation of the gas from the international border to East Aurora, New York and from there to the cogeneration facility in North East, Pennsylvania. To accomplish this, FSC stated that additional compression is required on the Niagara Spur Loop Line and National Fuel will also require compression on its own system to accommodate the Falcon Gas volumes. An application by National Fuel is expected to be filed by the fall of 1991 for the former and by the end of 1990 for the latter.

7.3.3 Sales Contract

FSC executed a gas purchase agreement on 28 November 1989 with Falcon Gas. Under the terms of the contract, FSC has agreed to supply Falcon Gas with 453 $10^3m^3/d$ (16 MMcfd) at the international boundary commencing in the period between 1 November 1991 and 1 November 1993 ("initial delivery date"). The agreement will continue for a period of 15 years from 1 November 1991, unless the term is reduced by Canadian or U.S. government authorities having jurisdiction over matters related to the contract. The price includes the costs incurred by FSC to purchase the supply in Alberta and to transport the volumes to Niagara Falls. Falcon Gas, in turn, executed a gas purchase agreement with NorCon to supply the gas to the cogeneration facility, comprising the supply acquisition costs at the international border and all transportation charges incurred on NOVA, TransCanada and National Fuel.

FSC pointed out that the terms and conditions of the contract between FSC and Falcon Gas which govern the export of the gas are essentially those included in the gas purchase agreement between FSC and WGML.

The FSC/Falcon Gas contract includes a number of conditions precedent, including: FSC and Falcon Gas receiving all regulatory approvals; WGML obtaining producer support; transportation agreements being executed between TransCanada and FSC and between National Fuel and Falcon Gas; and the cogeneration project receiving financing. All conditions must be satisfied or waived by 1 November 1993, otherwise the agreement is terminated.

The agreement recognizes FSC's buy-down provision in its contract with WGML. Under its contract with Falcon Gas, FSC can reduce the DCQ if it has sufficient alternate authorized supplies at prices which are acceptable to Falcon Gas. Falcon Gas has the right to require FSC, upon reasonable notice, to exercise its option to decrease the DCQ in the gas supply contract with WGML at the prescribed intervals. In the event of a buy-down of WGML's volumes, Falcon Gas must compensate FSC for the penalty fee required to be paid to WGML. The substitution of alternate supplies and the resulting reduction in WGML volumes cannot take place until all necessary regulatory and governmental approvals have been received.

Under the terms of the agreement, Falcon Gas is to pay FSC an export price that is comprised of a demand and a commodity component.

The demand component is comprised of the monthly demand charges paid by WGML for transportation on NOVA, TransCanada demand charges for transportation service contracted for by FSC and a reservation fee of $ 268.43 per 10^3m^3 of its DCQ.

The commodity component will be determined according to the following formula:

$$CC = ECCMP - DDC + CT$$

where:

- CC is the commodity charge.
- ECCMP is the eastern Canada core market price, equal to the immediately preceding month's weighted average selling price of all sales by WGML to four

eastern Canadian LDCs namely - ICG Utilities (Ontario) Ltd ("ICG (Ontario)"), Consumers', Union and Gaz Metropolitain, inc. ("GMi") - plus $ 0.05 per gigajoule, less the weighted average transportation charge from Empress to eastern Canada.

- DDC is the daily demand charge on NOVA.
- CT is the commodity toll equal to the sum of TransCanada commodity charges for transportation and charges for fuel gas used on TransCanada's system in transporting the gas.

In summary, the agreement provides for an export price, the commodity portion of which is based upon the monthly weighted average selling price plus $ 0.05/GJ ($ .05/MMBtu), at the Alberta/Saskatchewan border, received by WGML from eastern Canadian LDCs for gas sold to their core or high priority markets, less the NOVA demand charge.

Based on the foregoing contractual terms, the estimated price at the Alberta border as of January 1990 was $ Cdn. 2.30/GJ ($ Cdn. 2.47/MMBtu).

The agreement between FSC and WGML provides for renegotiation and, if necessary, arbitration if either party believes that the price payable by an LDC no longer reflects the price paid by its core market customers.

FSC stated that, although there were no take-or-pay provisions in the FSC/Falcon Gas contract, FSC, under its contract with WGML, was obligated to take a minimum of 75 percent of the annual contract quantity ("ACQ"). If FSC purchased less than the 75 percent in a given year, it would be required to make up the deficient volume in the subsequent year. In the event that FSC did not make up the deficiency, WGML would have the option to permanently reduce the DCQ, except if FSC exercised its right to maintain the DCQ by paying for the gas not taken. If, at the end of the fourth contract year, there were quantities of gas which should have been taken by FSC during the four-year period, FSC would have the option of either paying WGML for the volumes or agreeing to take the supply within the next five years. In any case, at the end of the subsequent five-year period, FSC would be obligated to pay WGML for any quantities not taken.

7.3.4 Power Sales Agreement

The proposed sale of electricity from the cogeneration plant will be pursuant to an agreement dated 28 April 1989 between NorCon and Niagara Mohawk. The agreement will continue for a period of 25 years from the commencement of commercial operations, which must occur no later than 18 July 1995.

The North East cogeneration plant is a must-run facility. Niagara Mohawk will pay a price that is equal to or below its avoided costs. Pricing is separated into three time periods, and includes an adjustment account. During the first period, prices are $ 0.06/kW.h. During the second period, prices are at 95 percent of Niagara Mohawk's avoided cost, as determined by the NYSPSC, subject to floor and ceiling prices incorporating Niagara Mohawk's long-run avoided costs. Thereafter during the third period, prices are equal to 90 percent of Niagara Mohawk's tariff avoided costs. The first period starts at the initial operation date until the adjustment account reaches zero. The second period, if any, is from the end of the first period to the end of year 15. The third period if any, consists of the period from the end of the second period to the end of year 25. The sale of electricity from the North East facility does not require wheeling by third parties.

7.3.5 Thermal Energy Sales Agreement

The proposed sale of thermal energy from the North East Plant would be pursuant to a thermal energy agreement, between Welch and Falcon Seaboard Oil Company. A letter of intent, for the thermal energy sale, was entered into on 25 October 1988, and subsequently amended. The letter of intent states that the thermal agreement will remain in effect for a period of 25 years from the initial operation date, making it contemporaneous with the power sale agreement. Welch's minimum steam purchases would be sufficient to ensure that the cogeneration plant maintains its QF status. As a part of its contractual obligations, the North East facility will provide Welch with electricity to run a

compressor system, should refrigerant from the cogeneration plant not be available.

The Applicant stated that negotiations with Welch were continuing and that a contract was expected to be executed by December 1990. At the time of publication of these Reasons, the Applicant had not advised the Board whether the steam sales contract had been executed.

7.3.6 *Regulatory Status*

The applied-for volumes would be removed from Alberta under TransCanada's existing AERCB permit TC-85-1 which was granted on 3 January 1986 and expires on 31 October 1999.

Falcon Gas received authorization from DOE/FE for a 15-year import order conditioned upon final environmental screening of facilities required to transport the gas.

The cogeneration facility received QF status from the FERC on 23 October 1989.

7.4 Views of Intervenors

Both Consumers' and Union opposed FSC's application for an export licence, primarily on the grounds of prematurity but also because of concerns with the buy-down provision in the WGML gas supply contract.

With respect to prematurity, Consumers and Union expressed concern that the facilities required to transport the gas in Canada and in the United States were yet to be built and that regulatory approval had not even been applied for. Union submitted that the fact that three major sets of regulatory approvals had not yet been applied for should be a "red flag" signalling the premature nature of a project.

Consumers' expressed concern about the lack of an executed steam contract, having regard to the fact that two years had lapsed since the signing of a letter of intent with Welch. Union argued that it was not possible for the Board or interested parties to undertake a meaningful analysis of a project when so much remained to be done. Union noted that negotiations with the steam host could result in changes to the original letter of intent, which should be subjected to the scrutiny of a public hearing and not merely dealt with by filing amended or additional information after the hearing.

Consumers' noted that FSC anticipated obtaining financing for the cogeneration facility by March 1991 and commencing plant construction in April 1991. Consumers' concluded that obtaining a licence from the Board did not appear to be a critical step in completing these stages of the project's development.

Consumers' characterized a gas supply contract with a buy-down provision as a short-term contract. Its reasoning was that the contract would be a long-term one only if FSC never exercised its option. However, Consumers' pointed out that FSC had indicated that it fully intends to buy-down the supply, and because of this Consumers' concluded that the WGML gas supply was intended as an interim one. Consumers' pointed to the linkage between fuel prices and power prices and questioned the ability to test this relationship without having any idea of what the terms and conditions of future supply arrangements might be.

With respect to the buy-down provision, Union argued that the Board should not issue a licence on the basis of a contract which permits FSC to reduce or terminate the WGML volumes upon payment of a modest compensation fee. Union submitted that it was not reasonable for FSC to ask the Board and the public to spend time in the public review process examining gas supply data and then to issue a decision on the sufficiency of that supply, only to have FSC substitute the entire volume, perhaps shortly after the licence was issued. In Union's view, the purpose of reviewing gas supply at a public hearing is defeated when alternate supply information can be filed after the hearing's conclusion.

WGML noted that it had come to the conclusion that the combination of the market-responsive pricing provisions and the potential benefit to it of the buy-down penalty provision, made its contract with FSC a viable commercial deal.

In replying to the concerns raised by Consumers' and Union, FSC agreed that a licence at this stage in the project's development was not critical for financing. However, FSC was of the opinion that

it had satisfied all of the requirements for the issuance of a licence.

With respect to the downstream facilities, FSC noted that it had executed a precedent agreement with National Fuel which obligated the latter to move ahead with facilities. FSC argued that any problem with the maturity of its project could be dealt with by a sunset clause. FSC offered to submit any new supply data to the Board if replacement was to occur, and stated its willingness to accept a licence condition directing them to do so. FSC stated that although Consumers' and Union felt that the buy-down provision was a weakness in the contract, FSC, on the other hand, was of the opinion that the ability to substitute other gas supply provided flexibility and strengthened the economics of the project.

FSC concluded that, although issuance of the licence was not critical to financing, it would help the project sponsors in dealing with bankers by demonstrating a long-term source of gas supply.

7.5 Views of the Board

The Board has reviewed the gas sales contract between WGML and FSC and the gas purchase contract between FSC and Falcon Gas. FSC acknowledged that, given its relationship with Falcon Gas, the export contract between them is not one which was negotiated at arm's length. However, as FSC pointed out, since the terms of this agreement are basically the same as those in the WGML agreement, which was negotiated at arm's length, the Board considers this to be an arm's length transaction.

The Board is satisfied that the demand component of the pricing structure in the export contract should ensure recovery of both NOVA's and TransCanada's fixed costs for transportation service to Niagara Falls. The Board notes that the commodity component of the pricing structure is tied to the weighted average price of WGML's sales to four eastern Canadian LDCs and, accordingly, is not responsive to the cogeneration facility's immediate market area. However, the Board recognizes that the buyer, in signing the agreement, feels that the commodity price, as indexed, will represent a price which will be competitive with gas sold in its market area. The Board also notes that the price is subject to renegotiation and arbitration, if necessary, and that the sales contract has received producer approval.

With respect to the buy-down provision in the WGML/FSC contract, the Board has taken into account the concerns raised by both Union and Consumers' with respect to the public's ability to scrutinize the supply and other arrangements which form the basis for the project. The Board shares Union and Consumers' concerns particularly with respect to the fact that FSC has indicated that it is actively negotiating for replacement supplies and gave the impression that replacement, at least in part, was imminent.

After much deliberation, the Board has decided that its concerns can be alleviated with the use of a condition in the licence issued to FSC for the Welch project. The licence will be conditioned to ensure that if, prior to commencement of exports, FSC replaces either its gas supply or its market, it will be required to seek approval of the Board. In doing so, FSC must provide the Board and interested parties to this hearing with information on the substitute gas supply or market in sufficient detail to allow the Board and others to gain an appreciation as to the nature and effect of the change and to allow the Board to decide, with input from interested parties, whether there is a need to conduct a public review of the amended supply or market arrangements. The Board notes that FSC, in response to cross examination by Consumers', stated that it would not object to a condition that would subject substitute supply to the same or similar scrutiny by the Board as the original gas supply.

A decision by FSC to replace the WGML supply after exports have commenced would entail amendments to the gas supply contracts which would not come into effect until after Board approval pursuant to section 35 of the Part VI Regulations. This would provide the Board with the opportunity to assess the effect of the amended arrangements and it would also give the Board the option of seeking input to its review from interested parties.

In addressing the question of completeness of evidence, the Board has reviewed the arguments of all concerned. The Board notes that, although there is no executed steam contract, a detailed letter of intent signed by both Falcon Seaboard Oil

Company and Welch has been filed. In addition, FSC filed a second letter from Welch indicating that the negotiations are still in progress. The Board also notes that there is an executed power sales contract with Niagara Mohawk for the sale of the generated electricity. The Board is satisfied that a market exists for the proposed export volumes.

Although facilities in both Canada and the United States are required to transport the gas and have not yet been applied for, the Board accepts FSC's argument that, with precedent agreements in place, there is reasonable expectation that these transportation arrangements will be finalized.

With respect to Consumers' and Union's arguments that this export application is premature and should be denied, the Board recognizes that certain arrangements relating to the steam host contract, financing and transportation are not finalized, but the Board is also of the view that the evidence is sufficient to assure the Board that, when in place, this export would be of satisfactory commercial substance and would serve a power project which represents a satisfactory long-term market. Furthermore, the Board, in conditioning the licence to prohibit the replacement of either gas supply or market without the Board's prior approval before gas can commence to flow under this licence, and by including a sunset clause, ensures that the nature of the project would not be different from that proposed in the submitted evidence.

The Board accepts FSC's argument that, although there are no take-or-pay provisions in the contract, Falcon Gas is contractually obligated to pay demand charges regardless of whether the gas moves or not. FSC is also obligated to take 75 percent of the DCQ over the first four years. If it does not, FSC must agree to take the shortfall over the next five years or pay the current commodity price for it. The Board is reasonably assured that, as a result of these provisions, the gas will be taken at a high load factor under this contract.

In addition, the Board is of the view that, in the light of the penalty payment that FSC would have to make to WGML in order to exercise its buy-down provision, FSC would only elect to buy-down the WGML supply if it were able to find a firm alternative source of supply at a price which would justify making the change.

7.6 Decision

The Board has decided to issue a gas export licence to FSC, subject to the approval of the Governor in Council. Appendix IV contains the terms and conditions of the licence, including a condition that the term of the licence shall commence on 1 November 1991 and shall end on 1 November 1993, unless exports have commenced under the licence on or before 1 November 1993, in which case the term would end on 31 October 2005. The Board has also decided to include a condition that requires that prior to the commencement of exports, FSC shall not, without Board approval, replace either its gas supply or its market from that described in its application and during the course of the GH-5-89 proceedings.

Chapter 8

Fulton Cogeneration Associates

8.1 Application Summary

By application dated 3 November 1989, as amended on 4 December 1989, Fulton applied under Part VI of the Act for a new gas export licence with the following terms and conditions:

Term	- Commencing 1 November 1991 and ending 31 October 2005 for a term of 14 years.
Point of Export	- Chippawa, Ontario.
Maximum Daily Quantity	- 326 10^3m^3 (11.5 MMcf) for the first 10 years. - 160 10^3m^3 (5.7 MMcf) for the last four years.
Maximum Annual Quantity	- 119 10^6m^3 (4.2 Bcf) for the first 10 years. - 58 10^6m^3 (2.1 Bcf) for the last four years.
Maximum Term Quantity	- 1 424 10^6m^3 (50.3 Bcf).
Tolerances	- 10 percent per day and 2 percent per year.

The proposed export volumes would be produced in Alberta and Saskatchewan from established reserves controlled by OMV (Canada) Ltd. ("OMV") and by Star Oil and Gas Ltd. ("Star"). The gas would be transported on NOVA in Alberta, on TransGas in Saskatchewan and via TransCanada to the proposed export point at Chippawa, Ontario. In the U.S., transportation is arranged on the Empire and Niagara Mohawk systems to provide gas service to a 47.4 MW cogeneration facility to be built in the city of Fulton, Oswego County, New York.

8.2 Gas Supply

8.2.1 Supply Contracts

Fulton has executed contracts with two producers: OMV for a term of 11 years and Star for a term of 15 years. Reserves are not contractually dedicated to the performance of these contracts but each producer has indicated its intent to utilize the identified reserves in the execution of these contracts and has indicated that substitution would only occur with Fulton's knowledge and consent. OMV is supplying its reserves from Alberta while Star's are from Saskatchewan.

Fulton indicated that certain natural gas reserves controlled by OMV and currently committed under long-term contract to ProGas, are being released from that contract and are, in turn, being dedicated to Fulton on a long-term basis.

Fulton stated that Star is currently delivering gas under a gas purchase contract with Unigas from the reserves which will be used to supply Fulton. Star and Unigas have agreed to terminate this contract effective 1 April 1991.

These contractual arrangements are discussed further in section 8.3.3 of these Reasons.

8.2.2 Reserves

Table 8-1 shows that the Board's estimate of Fulton's established gas reserves is four percent lower than Fulton's estimate and exceeds the applied-for volume by 55 percent.

Fulton's supply is comprised of reserves in Saskatchewan and Alberta. Fulton's estimates of reserves are 1 029 10^6m^3 (36.3 Bcf) in Saskatchewan and 1 272 10^6m^3 (44.9 Bcf) in Alberta. The Board's estimate of Fulton's reserves are 1 217 10^6m^3 (43.0 Bcf) in Saskatchewan and 991 10^6m^3 (35.0 Bcf) in Alberta.

Fulton's Saskatchewan reserves are located in the Hatton area, in Milk River, Medicine Hat and Second White Specks zones. The Milk River and Second White Specks zones are widespread, while

Table 8-1

Comparison of Estimates of Fulton's Established Gas Reserves With the Applied-for Volume

$10^6 m^3$ (Bcf)

Fulton[1]	NEB[2]	Applied-for Volume
2 301 (81)	2 208 (78)	1 424 (50)

1. As of 9 April 1990.
2. As of 31 December 1988.

the Medicine Hat zone is thin and areally restricted in Fulton's area.

The Board's estimate of Saskatchewan reserves is approximately 18 percent higher than Fulton's estimate. This discrepancy is primarily due to differences in interpretation of Milk River net pay obtained from well log data. The Board, however, agreed with Fulton's estimates of net pay for the Medicine Hat and Second White Specks zones.

The Board's estimate of reserves for Fulton's Alberta gas supply is 22 percent lower than Fulton's estimate. The Board recognized 34 pools in Alberta (31 of which are less than 100 $10^6 m^3$ (3.5 Bcf) in size) found in Cretaceous, Jurassic, Triassic and Devonian zones. Fulton's estimate of reserves included probable reserves that are approximately 14 percent of their total gas supply. The Board recognized all of Fulton's probable lands and discounted its reserves by the same risk factor (50 percent) as used by Fulton for these lands. The difference of 281 $10^6 m^3$ (10.0 Bcf) in the estimate of Alberta reserves is due mainly to interpretation of pool area. Several of the single-well pools were assigned full-section drainage areas by Fulton. The Board's analysis indicates that less than a full-section drainage is often appropriate, as described in Appendix II, and the Board was not satisfied in this circumstance that sufficient evidence was provided to support a larger area assignment for certain of the single well pools.

In summary, the Board's estimate of reserves is slightly lower than that of Fulton but exceeds the applied-for volume by a substantial amount.

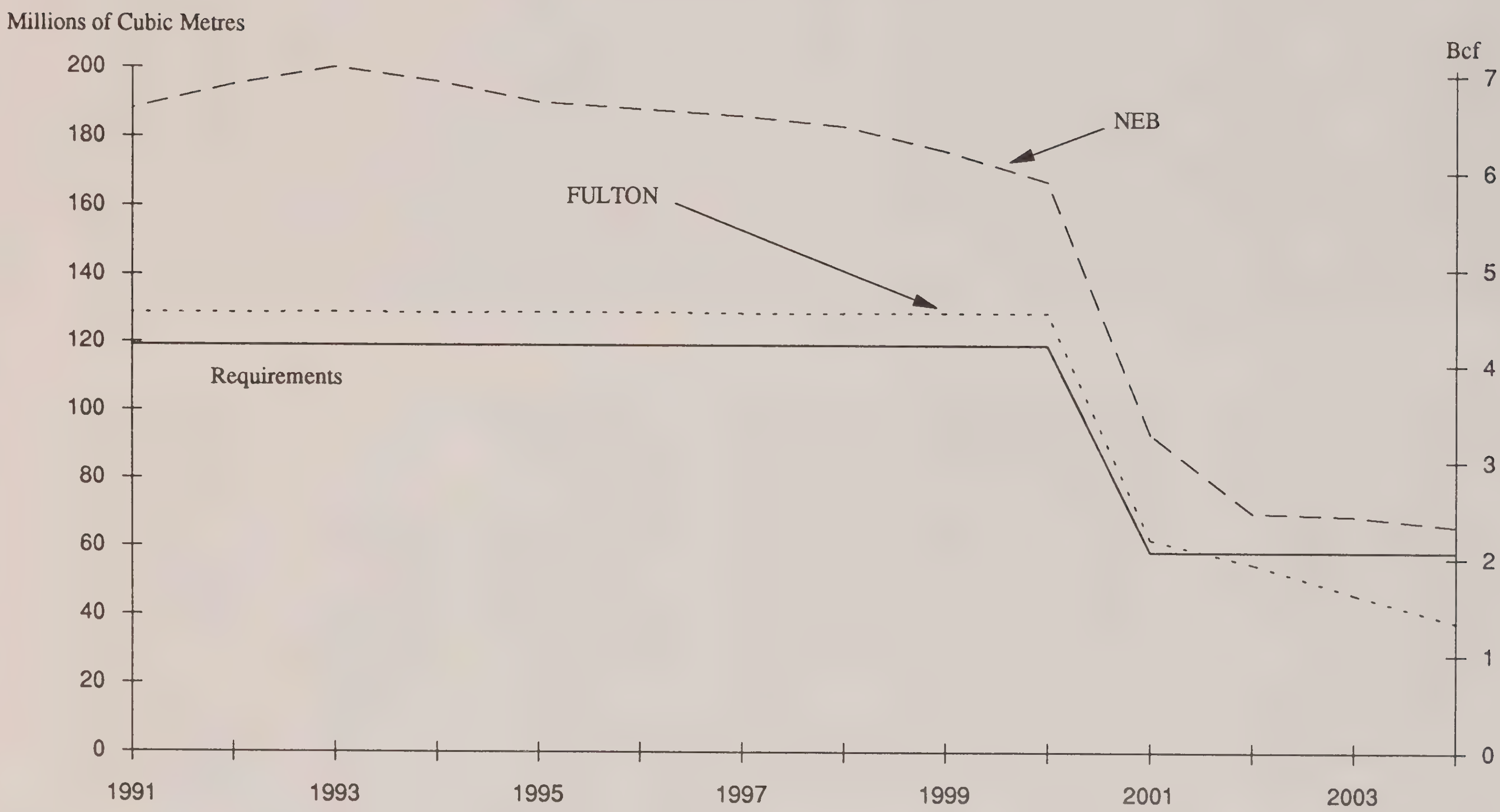
8.2.3 Productive Capacity

A comparison of the Board's and Fulton's estimates of productive capacity with the applied-for requirements is shown in Figure 8.1.

Fulton provided an estimate of its productive capacity which demonstrated that it was capable of meeting the applied-for requirements until the year 2001, after which minor shortfalls in supply were anticipated. Fulton's supply is provided by two producers, Star and OMV. Star was confident that its lands would in fact produce the necessary volumes but indicated that, if shortfalls did occur, it could supplement its supply from other uncontracted reserves in Alberta and Saskatchewan. OMV indicated that it had other reserves available, as well as sources of short-term deliverability and an extended exploration program, to meet any deficiencies in supply relative to requirements. Neither producer had any form of backstopping, but indicated that the

Figure 8.1

COMPARISON OF ESTIMATES OF ANNUAL PRODUCTIVE CAPACITY FOR FULTON



possibility of backstopping each other was being considered.

The Board's estimate of productive capacity from Fulton's reserves indicates that the applied-for requirements can be met throughout the term of the proposed export licence.

8.3 Market and Commercial Arrangements and Regulatory Status

8.3.1 Market

The gas would be used to fuel a 47.4 MW cogeneration plant to be located in Fulton, New York on land leased from the Nestle Food Corporation ("Nestle"). The plant is expected to be operational in early April 1991. The applied-for volume represents 100 percent of the plants total natural gas requirement during the first 10 years of operation and 50 percent thereafter. The electricity produced by the Fulton facility would be sold to Niagara Mohawk which provides electrical service to residential, commercial and industrial customers in its franchise area including the cities of Albany, Buffalo, Syracuse, and Watertown, New York. Fulton stated that since the plant will be operated as a must-run facility, Niagara Mohawk must purchase all of the generated electricity.

The thermal energy would be purchased by Nestle, a food processing company. It requires food-grade culinary steam for heating and cooling in the manufacture of chocolate food products. Nestle is contractually obligated to purchase enough steam to ensure maintenance of the facility's QF status.

Although financing for the $U.S. 48 million facility had not yet been put in place, Fulton stated that it had, at the time of the hearing, already expended $U.S. 30 million on the facility.

8.3.2 Transportation

The Alberta-sourced gas would be shipped to Empress, Alberta on the NOVA system. OMV, the Alberta producer, holds sufficient firm capacity on NOVA to transport the contracted volumes. Saskatchewan-sourced gas would be shipped by TransGas to the point of delivery near Success or Bayhurst, Saskatchewan. Star, the Saskatchewan producer, holds a long-term transportation agreement with TransGas which, with renewals, would provide sufficient capacity for delivery of the contracted volumes.

TransCanada would then transport the gas from the Empress, Alberta and Bayhurst, Saskatchewan receipt points to Chippawa, Ontario for delivery to the point at the international border where TransCanada facilities would interconnect with the proposed Empire system. TransCanada and Fulton have entered into a precedent agreement dated 8 December 1989, as amended 12 October 1990, for firm transportation of 354 $10^3m^3/d$ (12.5 MMcfd) beginning 1 November 1991. Since Fulton is the shipper on TransCanada, it would be responsible for the relevant TransCanada fixed cost of transportation. In addition to the incremental mainline facilities required on TransCanada to transport the Fulton volumes, there would also be a requirement for a new extension from Kirkwall to Chippawa, Ontario which is the subject matter of a separate TransCanada filing under section 58 of the Act and is referred to as the "Blackhorse Extension". This application is the subject of a separate hearing.

In the U.S., the gas would be transported by the proposed Empire system from the international border to the interconnection of the Niagara Mohawk system at Syracuse, New York. Fulton has entered into a precedent agreement dated 17 May 1989, as amended 17 April 1990, with Empire for firm transportation of 340 $10^3m^3/d$ (12 MMcfd) for a period of 18 years beginning 1 November 1991. Fulton indicated that the transportation on Empire is uncertain at this stage, however, it expected that the necessary approval from the NYSPSC would be received shortly.

The Fulton volumes would then be received by Niagara Mohawk at Syracuse, New York and delivered to the cogeneration facility. Fulton has executed an agreement in principle with Niagara Mohawk for transportation of the contracted volumes for a term of 18 years. Construction on the Niagara Mohawk system is required to transport the Fulton volumes, and is expected to commence shortly.

Fulton stated that there were several transportation options available to them in the event that Empire was delayed or if it was not built at all. These options included the use of firm service on Tennessee, or Great Lakes Gas Transmission Company ("Great Lakes") to ANR Pipeline Company ("ANR") to CNG Transmission Corporation ("CNG") as well as others. Fulton pointed out that, with completion of the cogeneration facility, it would have spent approximately \$U.S. 48 million and that this, combined with its commitment to OMV and Star, would ensure that Fulton would diligently pursue one of the U.S. transportation options that was available to it.

Fulton indicated that the cogeneration facility would be 92 percent complete by the end of 1990 and the start-up phase would occur in early 1991. In the interim, Fulton plans to use interruptible transportation and its short-term gas export Order GO-119-90, to export gas at Niagara Falls, Ontario. In the U.S., Fulton stated that it would use interruptible transportation on a least-cost and availability basis.

8.3.3 Gas Sales Contracts

Fulton has entered into natural gas sales agreements with two producers, OMV and Star.

8.3.3.1 OMV (Canada) Ltd.

Fulton and OMV executed a gas sales agreement dated 27 October 1989, as amended on 11 May and 12 September 1990, for a term of 11 years. Under the terms of the contract, deliveries of up to 184 10^3m^3/d (6.5 MMcfd) are expected to begin on 1 April 1991. The agreement is subject to several conditions precedent, including receipt of all Canadian and U.S. regulatory approvals and finalization of all Canadian and U.S. transportation arrangements. These conditions precedent are to be satisfied by 1 February 1991; otherwise, either party may terminate the contract by written notice. If, by 31 March 1991, neither party has opted to terminate the agreement, then, the unsatisfied conditions will be deemed to have been waived for all purposes.

The agreement provides that OMV is responsible for all NOVA transportation charges.

The OMV contract has a 55 percent take-or-pay provision for the first two years, and an 80 percent take-or-pay provision for the remainder of the term. Fulton stated that the reason for the lower initial take-or-pay provision is to give the project some flexibility to respond to construction delays or technical problems which may arise in the plant's early stages. Fulton has estimated a 95 percent load factor under this contract as a result of the above mentioned take-or-pay provision and because Fulton is contractually obligated to pay the demand charges whether or not the gas is moved.

The OMV contract contains pricing provisions which permit annual price adjustments to reflect changing market conditions. Base prices are specified for each contract year beginning at \$ U.S. 1.71/GJ (\$ U.S. 1.80/MMBtu) for the first contract year beginning on 1 April 1991 and increasing by three percent each year to \$ U.S. 2.29/GJ (\$ U.S. 2.42/MMBtu) for the eleventh contract year. The price is then determined annually to be the greater of:

a) the current contract year's base price; or

b) \$ U.S. 1.61/GJ (\$ U.S. 1.70/MMBtu) escalated by a factor tied to the weighted average sales price for electricity received by Fulton during the previous year; or

c) 80 percent of the published Average Alberta Market Price ("AAMP").

Based on the foregoing contractual terms, the price at the Alberta border, as of January 1990, would have been \$Cdn. 1.93/GJ (\$Cdn. 2.07/MMBtu).

The contract allows for renegotiation and arbitration, if necessary, in order to determine a substitute pricing mechanism in the event that the AAMP ceases to be published.

8.3.3.2 Star Oil and Gas Ltd.

Fulton has executed a gas sales agreement with Star dated 23 October 1989. This gas contract was later amended on 25 April 1990 and 12 September 1990. The agreement is in effect for a term of 15 years beginning 1 April 1991 and provides for the daily delivery of up to 170 10^3m^3 (6.0 MMcf) of gas at Chippawa, Ontario.

The gas contract is subject to several conditions precedent including receipt of all Canadian and U.S. regulatory approvals, finalization of all Canadian and U.S. transportation arrangements, the buyer obtaining a commitment for project financing and construction of the cogeneration project. The conditions precedent are to be satisfied by 1 February 1991, otherwise, either party may terminate the contract upon written notice.

As a result of the 80 percent take-or-pay provision in the Star/Fulton contract, and because Fulton is contractually obligated to pay the demand charges whether or not the gas is moved, Fulton expects to take the gas at approximately 95 percent load factor .

Under the provisions of the contract, the price is determined using a base price of $ U.S. 1.80/GJ ($ U.S. 1.90/MMBtu) for 1 April 1991. This price is then increased by three percent per year for each contract year beginning on 1 November 1991 unless the actual sale price for electricity sold by Fulton exceeds $ U.S. 0.07/kW.h at the beginning of any contract year. The price for that contract year would then be determined as the greater of:

a) the previous contract year's price increased by three percent; or

b) the previous contract year's price increased by 80 percent of the change in the U.S. Implicit Price Deflator for the Gross National Product for the previous 12 months; or

c) 80 percent of the average of the AAMP published for the previous 12 months.

Based on the foregoing contractual terms, the price at Success, Saskatchewan, as of January 1990, would have been $Cdn. 2.06/GJ ($Cdn. 2.21/MMBtu).

Six months prior to the twelfth contract year, Fulton and Star will renegotiate the pricing mechanism for the remaining term of the contract. Should they fail to agree on a formula, the agreement will terminate after the eleventh contract year. Star is responsible for transportation demand charges incurred up to the inlet to TransCanada's system.

8.3.4 Power Sales Agreement

The proposed sale of electricity from the Fulton cogeneration plant will be pursuant to an agreement dated 10 December 1987 between the Turner Power Group, Inc. ("Turner") and Niagara Mohawk. In an assignment agreement dated 1 February 1988, Turner assigned the power agreement to Fulton. The agreement will continue for a term of one year from the initial operation date and continuously thereafter until it is cancelled by Fulton on 90 days notice.

The Fulton cogeneration plant is a must-run facility, with Niagara Mohawk purchasing all the electricity that is produced by the plant which is designed to generate approximately 392,000 MW.h of energy annually. The price Niagara Mohawk would pay is Niagara Mohawk's avoided-cost rate, as that rate may be changed or approved by the NYSPSC. If the NYSPSC rate is deleted, then rates will be calculated as set out in the agreement. The agreement rates include peak and off-peak pricing and are calculated for projected avoided production, capacity and transmission costs as approved by the NYSPSC. The electricity sold from the Fulton facility does not require wheeling by third parties.

8.3.5 Thermal Energy Sales Agreement

Nestle will sell or lease Fulton up to three acres of land for its proposed plant. The proposed sale of thermal energy from the Fulton plant will be pursuant to the amended and restated steam services agreement, dated 9 June 1988, as amended, between Fulton and Nestle. From the commencement date of operation the contract will continue for a term of 18 years but, upon mutual agreement, can be extended for five years following which the agreement may be extended for further terms. Nestle is obliged to purchase sufficient thermal energy so that the cogeneration plant will maintain its QF status. To ensure the thermal supply to Nestle, Fulton will maintain a stand-by steam supply facility or secure an emergency steam system. Nestle can use its existing boilers at any time Fulton cannot provide steam or operate the stand-by facilities. Nestle may acquire, at no charge to Fulton, stand-by or back-up steam service or equipment. Steam will be sold to Nestle at a discounted rate. Should

Nestle terminate its operations at this site after the tenth anniversary of the thermal agreement, the parties to the thermal agreement will attempt to find a substitute steam host to maintain QF status.

8.3.6 Regulatory Status

Fulton, as agent for Star, filed an application with Saskatchewan on 3 November 1989 for a long-term removal authorization for the period 1 November 1991 to 31 October 2005. On 4 December 1989 Saskatchewan sent a letter to Star indicating that it would recommend that the Minister of Energy and Mines issue an energy removal permit, subject to a number of conditions. Star indicated during the hearing that a long-term permit from Saskatchewan was expected to be received once the requirement for downstream regulatory approvals had been met.

On 3 November 1989 OMV applied to the AERCB for a long-term removal permit for the period 1 November 1991 to 31 October 2001. OMV indicated that the permit was expected to be received before the end of 1990. In this regard, Fulton has stated that the AERCB has recommended that the Department of Energy issue the requested removal permit to OMV.

On 25 February 1990, Fulton, as agent for Star and OMV applied to Saskatchewan and the AERCB respectively for short-term removal permits for the period from 1 November 1990 to 31 October 1991. These permits have been granted and gas will be removed pursuant to them and exported at Niagara Falls, Ontario under Fulton's short-term export order during the period between start-up and a licence being issued.

Fulton applied to the DOE/FE for import authorization on 25 April 1990. Fulton testified that the authorization has been delayed pending the outcome of, among other things, its Part VI application.

The facility has received QF status from the FERC.

8.4 Views of Intervenors

CNG has expressed the view that the Board should not be licensing exports of Canadian gas at Chippawa in the face of uncertainty regarding related transportation arrangements. CNG went on to say that if a licence was granted to Fulton, it should be conditioned in such a way as to take into account these uncertainties. A more complete description of CNG's suggested licence conditions is included in section 12.4 of these Reasons.

8.5 Views of the Board

The Board is satisfied with the adequacy of Fulton's supply relative to the proposed requirements.

The Board is satisfied that the markets for the electricity and steam produced by the Fulton cogeneration facility are secure and that the facility would operate at a high load factor.

The Board notes that QF certification, DOE/FE import authorization, and most other regulatory approvals and authorizations required for this cogeneration facility have been obtained. The Board is of the view that the remaining authorizations and approvals are likely to be forthcoming, given the evidence that the Fulton facility would likely be completed by early 1991.

The Board notes that transportation has been arranged on all required pipelines. The gas sales contractual arrangements would ensure that demand charges on NOVA, TransGas and TransCanada are recovered. In this regard, the Board notes that Fulton would provide a letter of credit to TransCanada from its bankers for a term of two years and in an amount equal to one year of TransCanada's firm service demand charges based on Fulton's full contracted operating demand volumes times the then prevailing NEB-approved firm service demand toll.

The Board is satisfied that the index mechanism in both gas sales contracts would permit the export price to respond to changing market conditions. In this regard, the Board notes that, while explicit provision for renegotiation and arbitration are not present in the case of OMV, the contract was negotiated at arm's length. Star, on the other hand, has provision for price

redetermination after the eleventh year of the contract. Therefore, the Board is of the view that the market responsive pricing formulas would ensure adequate levels of take under the gas sales contracts. The Board further notes that the combination of take-or-pay provisions and demand charge responsibility would also help to ensure high levels of take under the two sales contracts.

The Board considers that the transportation situation downstream, with respect to the Empire State project, remains unresolved at this time and whereas the NYSPSC has approved the Empire State project, on the Canadian side, TransCanada's application for the Blackhorse extension is currently before the Board. The Empire State project is contingent upon the Board's approval of TransCanada's application. The Board notes, however, that there are a number of different transportation options available to move the contracted volumes of gas to the Fulton plant. It is the Board's view that, given its financial commitment to the project, Fulton would actively pursue alternative, least-cost transportation routes in the event that Empire State was unable to proceed.

The Board has reviewed the gas sales contracts and notes that both have been negotiated at arm's length and that OMV and Star have endorsed the proposed export by virtue of their having executed the contracts.

8.6 Decision

The Board has decided to issue a gas export licence to Fulton, subject to the approval of the Governor in Council. Appendix IV contains the terms and conditions of the licence, including a condition that the term of the licence shall commence on 1 November 1991 and shall end on 1 November 1993, unless exports have commenced under the licence on or before 1 November 1993, in which case the term would end on 31 October 2005.

Chapter 9

Indeck Gas Supply Corporation - Indeck Corinth

9.1 Application Summary

In an application dated 30 November 1989, as amended, Indeck Corinth, by its agent Northstar Energy Corporation ("Northstar"), sought approval, pursuant to Part VI of the Act, of a natural gas export licence.

The applied-for licence requested the following terms and conditions:

Term	- Later of 1 November 1991 or the date of first deliveries, for a period of 15 years
Point of Export	- near Chippawa, Ontario
Maximum Daily Quantity	- 459 10^3m^3 (16.3 MMcf)
Maximum Annual Quantity	- 168 10^6m^3 (6.0 Bcf)
Maximum Term Quantity	- 2 439 10^6m^3 (86.6 Bcf)
Tolerances	- 10 percent daily and 2 percent monthly

The proposed export volumes would be produced from established reserves in Alberta controlled by Devnic Energy Inc. ("Devnic"), Northstar and a producer group consisting of Inverness Petroleum Ltd. ("Inverness"), Universal Exploration Ltd. ("Universal") and Altex Resources Ltd. ("Altex").

The gas would be sold to Indeck Energy Services of Corinth, Inc. ("Indeck Services Corinth").

The gas would be transported to the Alberta/Saskatchewan border, at Empress, on the NOVA system. From Empress, it would be delivered by TransCanada to the international boundary near Chippawa, Ontario. In the U.S., National Fuel would transport the gas to the facilities of CNG at Elma, New York. CNG would, in turn, deliver the volumes to the village of Corinth, New York, where Niagara Mohawk would construct a connecting pipeline to a cogeneration plant to be built and owned by Indeck Services Corinth. Consolidated Edison Company of New York, Inc. ("Con Ed") would purchase the electricity and International Paper Company ("International Paper") would acquire the steam.

9.2 Gas Supply

9.2.1 Supply Contracts

To meet its supply requirements Indeck Corinth executed three separate long-term supply contracts, with Devnic, Northstar and an aggregated group consisting of Inverness, Universal and Altex. The Northstar contract has a term of 12 years. The other two have 15-year terms.

Each of these producers has dedicated specific fields to satisfy the regulatory requirements of the project and is required by the gas purchase agreement to provide an engineering report each year demonstrating that sufficient reserves and deliverability are dedicated to Indeck Corinth to meet the MDQ for a period of five years.

In the event of a shortfall in supply, the producers may dedicate additional reserves to the execution of the contract. However, they are not obligated to do so. Should Indeck Corinth be required to obtain additional supply from other sources to address shortfalls, the producers are required to reimburse any additional costs incurred by Indeck Corinth.

These contractual arrangements are discussed further in section 9.3.3 of these Reasons.

9.2.2 Reserves

Table 9-1 shows that the Board's estimate of Indeck Corinth's established reserves and undiscovered potential is 14 percent lower than Indeck Corinth's estimate, but exceeds the applied-for volume by 14 percent.

Table 9-1

Comparison of Estimates of Indeck Corinth's Established Gas Reserves and Undiscovered Potential With the Applied-for Volume

$10^6 m^3$ (Bcf)

	Indeck Corinth[2]	NEB[1]	Applied-for Volume
Established Reserves	3 213 (113)	2 530 (89)	
Undiscovered Potential		246 (9)	
Total	3 213 (113)	2 776 (98)	2 439 (87)

1. As of 31 December 1988.
2. As of 1 September 1989 and revised 30 November 1990. Indeck Corinth also estimated remaining reserves of 2 934 $10^6 m^3$ (103.6 Bcf) as of November 1991.

The Board's estimate includes an allowance for undiscovered potential, which makes up ten percent of the Board's total estimate of supply.

The divergence in estimates of reserves arises predominantly from differing interpretations of the Riviere area (St. Albert - Big Lake and Acheson East Fields as defined by the AERCB). Indeck Corinth assigned proven reserves in the Basal Belly River zone to six of 11 sections of land under its control. Two of the remaining five sections were assigned probable reserves, discounted by a risk factor. In addition, Indeck Corinth assigned probable reserves to five sections of land in a lower Basal Belly River zone that occurs in this area, again on a discounted basis. Indeck Corinth applied full-section drainage areas to all of the above assignments, yielding a total reserve for the Riviere area of 683 $10^6 m^3$ (24.1 Bcf).

The Board did not concur with the volume of proven and probable reserves assigned by Indeck Corinth, as there are four abandoned wells in the Basal Belly River zone in this immediate area, two of which are on Indeck Corinth lands. The Board assigned two sections of proven reserves, one section of probable reserves and four sections of potential in the Basal Belly River zone, applying risk factors to the probable and the potential. Within the lower Basal Belly River zone, the Board recognized five full sections of potential. The Board's analysis yielded an estimate of established reserves for Indeck Corinth's Riviere lands of 149 $10^6 m^3$ (5.2 Bcf) and an estimate of undiscovered potential of 246 $10^6 m^3$ (8.7 Bcf).

The Board's lower estimate of reserves for the Riviere area accounted for approximately 66 percent of the overall difference in the total estimates of remaining reserves and undiscovered potential.

There is also a variance in estimates of reserves due to ownership interpretation in the Whitecourt Jurassic D pool. Indeck Corinth estimated that its well would have 31.25 percent of the remaining reserves of the pool, or 533 $10^6 m^3$ (18.8 Bcf), based on the ratio of their wells' productive

capacity to the total pool productive capacity. The Board used a pore volume weighting to estimate reserves for the Indeck Corinth well. This results in an ownership interpretation of 20 percent, as opposed to Indeck Corinth's 31.25 percent. This lower estimate for the Whitecourt Field accounted for about 30 percent of the overall difference in estimates between the Board and Indeck Corinth.

Fourteen single-well pools (approximately 30 percent of Indeck's single-well pools) were assigned full-section drainage areas by Indeck. The Board's estimate of reserves for most Cretaceous single-well pools is based on a smaller area assignment. The Board did not find sufficient evidence in the pools assigned larger drainage areas by Indeck Corinth to warrant significantly altering its view as to the appropriate area assignment for these single-well pools. This group of pools contributed to about 13 percent of the overall difference between the Board's and Indeck Corinth's estimates.

In its analysis of Indeck Corinth's gas supply, the Board recognized 72 established gas pools, the majority of which are not producing. Most of the pools are relatively small and located in the east-central portion of Alberta in Cretaceous sands. Seventy-six percent of the pools for which Indeck Corinth submitted reserves have reserves estimated by the Board to be less than 100 $10^6 m^3$ (3.5 Bcf) of initial marketable gas.

In summary, the Board's estimate of reserves is lower than Indeck Corinth's estimate but exceeds the applied-for volume. The divergence in estimates is related primarily to differences in evaluation of proven and probable reserves and undiscovered potential associated with the undrilled lands, area assignments for single-well pools and ownership interpretation for one pool.

9.2.3 Productive Capacity

A comparison of the Board's and Indeck's estimates of productive capacity with the applied-for requirements is shown in Figure 9.1

Indeck's estimate of annual productive capacity represents its forecast production rate at a 94 percent load factor. It indicates that requirements would be fully met until 1995, with increasing deficiencies anticipated throughout the remainder of the term of the proposed export licence. Indeck stated that its producers would endeavour to maintain the required deliverability rate through either further development of the existing areas or the addition of reserves from other areas under the producers' control.

None of Indeck's producers have formal backstopping agreements, although some preliminary discussions had been held in regard to an agreement whereby they would backstop each other. Indeck indicates that any short-term deficiencies in supply would be alleviated by purchases from the Alberta spot market and producers had the right to dedicate additional reserves should long-term deficiencies arise.

The Board's estimate of productive capacity for the Indeck Corinth project was very similar to that of the Applicant. The Board's projection includes a small volume of undiscovered potential described in section 9.2.2 and Table 9-1.

9.3 Market and Commercial Arrangements and Regulatory Status

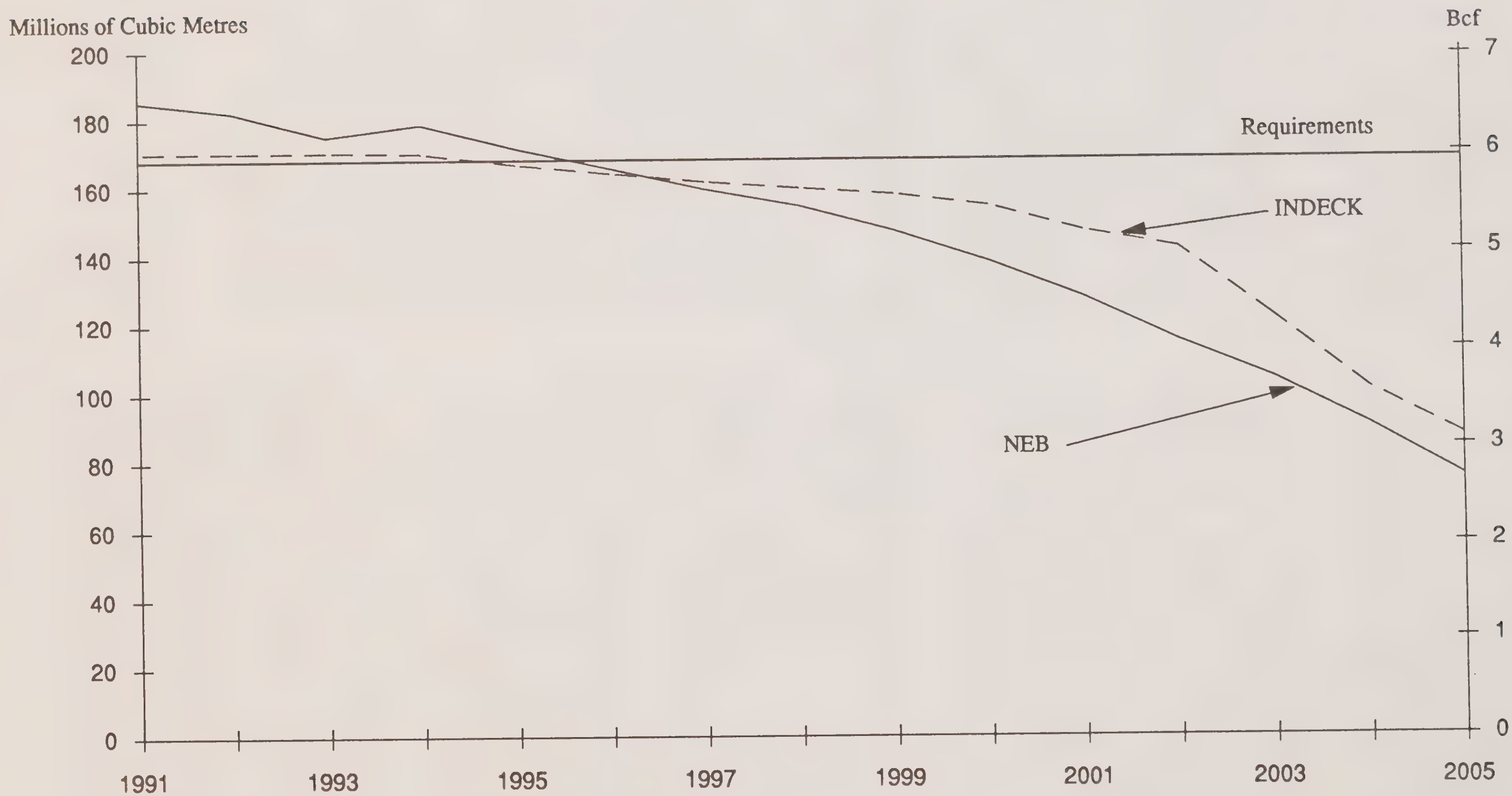
9.3.1 Market

The Corinth cogeneration plant, expected to be in commercial operation in December 1992, is rated between 132 MW under winter ambient conditions and 103 MW during the summer and will be located at the Hudson River Mill of International Paper on a site purchased from the steam host. The steam will be used for heating pulp and drying the paper required in the production of coated publication paper for magazines and commercial reports. Con Ed, the electric power purchaser, supplies electric service in New York City and most of Westchester County. The company also supplies gas to Manhattan, the Bronx, parts of Queens and Westchester as well as steam in parts of Manhattan. The cogeneration plant will provide Con Ed with an electrical output of approximately 971,000 MW.h annually.

As a result of the consideration of tolling methodology in the GH-5-89 proceedings, financial closing for the Corinth project was delayed. However, in light of the Board's ruling,

Figure 9.1

COMPARISON OF ESTIMATES OF ANNUAL
PRODUCTIVE CAPACITY FOR INDECK CORINTH



project financing is expected to close by the end of the first quarter of 1991.

Indeck Corinth stated that the gas proposed for export would satisfy approximately 73 percent of the cogeneration facility's requirements. Indeck Corinth testified that the minimum operating load factor is forecasted to be 94 percent during each year of the term of the proposed licence. This forecast took into account the plant's maintenance schedule and the contract's minimum take-or-pay obligation of 94 percent. However, given Indeck Corinth's ability to divert gas to other cogeneration facilities, it is expected that the actual load factor will be 100 percent.

9.3.2 Transportation

The proposed export volumes would be transported to the Alberta/Saskatchewan border, at Empress, on the NOVA system. From Empress, the gas would be delivered by TransCanada to the international boundary at Chippawa, Ontario. In the U.S., National Fuel would transport the gas to the facilities of CNG at Elma, New York. CNG would, in turn, deliver the volumes to the village of Corinth where Niagara Mohawk would construct a connecting pipeline to the cogeneration facility.

Within Alberta, the producers have requested firm, long-term transportation service with NOVA to deliver the proposed export volumes to Empress. Indeck Corinth has executed a precedent agreement with TransCanada dated 8 December 1989 to transport the gas from Empress to Chippawa and a financial assurances agreement dated 12 February 1990. Indeck Corinth would thus be directly responsible for demand charge payments on TransCanada.

In the U.S., Indeck Services Corinth has entered into a precedent agreement with National Fuel dated 5 November 1990 for the transportation of the gas from the international boundary to a point of interconnection with the CNG system at Elma, New York. CNG has provided a letter to Indeck Services Corinth dated 20 April 1990 expressing its intention to work with Indeck Services Corinth to arrange necessary transportation. A precedent agreement is currently under negotiation. From the Corinth city gate, Niagara Mohawk would deliver the gas to the cogeneration facility through a six-mile pipeline extension for which an application was expected to be made to the NYSPSC. Indeck Services Corinth and Niagara Mohawk are currently negotiating a precedent agreement.

9.3.3 Gas Sales Contract

In its role as the party responsible for acquiring natural gas supplies, Indeck Corinth executed three gas purchase agreements of which two were with individual producers, Devnic dated 3 October 1989 and Northstar dated 1 November 1989 and one was with the Inverness, Universal and Altex producer group dated 6 November 1989. In turn, Indeck Corinth concluded a gas sales and purchase agreement with Indeck Services Corinth dated 10 October 1989, under which the latter agrees to pay the costs incurred by Indeck Corinth to acquire the gas at Empress and to transport the volumes to Chippawa.

The terms and conditions of the contract governing the export of the gas are essentially those included in the gas purchase agreements between Indeck and the Alberta producers. These arrangements, which include fuel, are as follows:

Producer	Volume (MMcfd)
Devnic Energy Inc.	8.0
Northstar Energy Corporation	2.5
Producer group, consisting of:	
Inverness Petroleum Ltd.	3.0
Universal Exploration Ltd.	2.0
Altex Resources Ltd.	2.0

The agreements include a number of conditions precedent. Producers are responsible for obtaining provincial removal permits and for arranging firm transportation on NOVA. Indeck Corinth is responsible for obtaining an NEB export licence and a U.S. import permit, and for concluding transportation arrangements from Empress to Chippawa and, through agreement with Indeck Services Corinth, from the international boundary to Corinth. All conditions must be satisfied by 1 November 1991, otherwise the arrangements may be terminated by either party on ten days notice.

The agreements define the MDQ as the producer volumes mentioned above and the minimum obligation as the MDQ less any quantities which Indeck Corinth is unable to take because of force majeure or regularly scheduled outage defined as scheduled cogeneration plant shutdown for routine inspection, maintenance and repair which is limited to a maximum of 21 days in any contract year. Indeck Corinth undertakes to purchase the minimum obligation in each contract year on a take-or-pay basis. In the case of volumes paid for but not taken (i.e., deficient quantities), Indeck Corinth has the right to request delivery of this gas, without charge, for a period of up to two years after the expiry of the gas purchase agreements. The arrangements also provide for a situation whereby, if Indeck Corinth does not purchase the minimum obligation for two consecutive years, the producers may reduce the MDQ to the average volume actually taken during the two-year period when the shortfall occurred.

Under the pricing provisions of the agreements, producers are responsible for the payment of the demand charge on NOVA. Indeck Corinth is committed to pay the demand charge on TransCanada which, under the terms of the agreement, is added to the commodity charge to arrive at a total price at Chippawa. Indeck Services Corinth incurs this cost and has responsibility for transportation downstream of the international boundary.

The commodity charge to be paid by Indeck Corinth to the producers, at the Alberta/Saskatchewan border, will be determined on the basis of a negotiated base price for May 1989, reflecting Con Ed's average cost of all purchased gas ("ACAPG") in April 1989 of \$ U.S. 2.37/GJ (\$ U.S. 2.50/MMBtu). For May 1989, the negotiated base prices at Empress were as follows:

Producer	May 1989 Base Price
	(\$ U.S./MMBtu)
Devnic	1.48
Northstar	1.55
Producer group	1.53
Weighted Average	1.51

The actual prices to be paid to the producers in any given month will be the adjusted base prices, essentially reflecting the proportional change in Con Ed's ACAPG. For the three producer contracts as a whole, the formula used for determining any month's producer price, at Empress, will be as follows:

$$\text{Producer price} = \frac{\$\text{ U.S. } 1.51/\text{MMBtu}}{\$\text{ U.S. } 2.50/\text{MMBtu/previous month}} \times \text{ACAPG}$$

where: \$ U.S. 1.51/MMBtu was the weighted average producer price for May 1989.

\$ U.S. 2.50/MMBtu was Con Ed's ACAPG in April 1989.

For deficient volumes, Indeck Corinth is required to pay producers a weighted average of the prices applicable during the year in which the deficiency occurred.

Indeck Corinth indicated that the price at the Alberta border in January 1990 would have been \$ Cdn 2.024/GJ (\$ U.S. 1.823/MMBtu).

While the contracts do not provide for price renegotiation or arbitration, Indeck Corinth stated that these features were not required because the prices were market-driven.

9.3.4 Power Sales Agreement

The proposed sale of electricity from the Corinth cogeneration plant will be pursuant to the power purchase agreement dated 15 September 1989 between Con Ed and Indeck Services Corinth. The agreement will continue for a period of 20 years from the commercial operation date.

The Corinth cogeneration plant will be dispatched on economic as well as safety and reliability considerations by Con Ed, whereby Con Ed schedules and controls the generation of electricity from the facility to its system. When dispatched, the plant will be operated at full available output. Under the power purchase agreement the cogenerator has no right or entitlement to any minimum payment that may be specified by law. The price includes payments for capacity, energy, transportation, operation and maintenance and an electrical service payment. All the payments include escalation provisions. A fuel savings rebate is paid by the Corinth cogeneration facility to Con Ed. Con Ed is

required to pay 85 percent of Corinth's fixed costs, even if the plant is dispatched below 85 percent. The 85 percent payment is dependant upon the plant being available for dispatch. Should the plant lose its QF status, Con Ed will pay a rate equal to 90 percent of either the rate as it is calculated in the agreement, or as determined by Con Ed's NYSPSC tariff. If rates are based on avoided cost and the cogenerator has operating control over the plant, it becomes a must-run facility and Indeck Services Corinth pays for the transmission and scheduling of electricity by Niagara Mohawk.

The sale of electricity from the Corinth plant requires wheeling by Niagara Mohawk. Indeck Corinth has undertaken to file the executed wheeling agreement with the Board upon its execution.

9.3.5 Thermal Energy Sales Agreement

The proposed sale of thermal energy from the Corinth plant will be pursuant to the energy supply agreement dated 30 October 1989 between Indeck Services Corinth and International Paper. The agreement will continue for a period of 20 years from the commercial in-service date and may be extended for periods of five years. International Paper is obliged to purchase sufficient thermal energy to enable the cogeneration facility to maintain its QF status. Should the minimum QF steam amount not be taken, International Paper under certain conditions may be required to pay for the minimum amount and sell vacant land for $ 1 to allow for the construction of an affiliated thermal consuming business. Should International Paper lose the ability to provide steam from its own boilers, the cogenerator will endeavor to supply extra steam.

9.3.6 Regulatory Status

Indeck Corinth applied to the AERCB on 15 December 1989 for a long-term energy removal permit. The application specified a term of 15 years and a term volume of 3 538 10 ^{6}m^3 (125 Bcf), which includes the Indeck-Ilion volumes (see section 10.3.6). Approval is expected in the spring of 1991.

Indeck Services Corinth applied for DOE/FE import authorization on 22 January 1990. No objections have been filed and approval is expected by May 1991.

The cogeneration facility has been granted FERC QF status.

9.4 Views of Intervenors

Consumers' opposed the issuance of a licence to Indeck Corinth because in its view the Applicant had not demonstrated that all significant contractual arrangements and regulatory approvals were in place or sufficiently well advanced to justify an export authorization.

With respect to downstream transportation, Consumers' noted that, since the application was filed, there had been several changes to the export point and to downstream arrangements relating to whether or not the Empire State pipeline would be utilized. Specifically, Consumers' noted that Indeck Corinth had originally indicated that the gas would be exported at Niagara Falls and be transported by National Fuel on the Niagara Spur to CNG's facilities in Marilla, New York. Indeck Corinth then indicated that the gas would be transported on National Fuel's "Empire Alternative". Following the resolution of a dispute between National Fuel and Empire, Indeck Corinth now proposes that the export would be made at Chippawa and be transported on National Fuel's entitlement on the proposed Empire system to an interconnection with CNG's facilities at Elma, New York under a new precedent agreement between Indeck Services Corinth and National Fuel. Consumers' noted that this precedent agreement includes a provision that, in the event that it is terminated, the original precedent agreement utilizing the Niagara Spur would come back into force. Consumers' assumed that if this were to occur, the export point would then become, once again, Niagara Falls and noted that there was no evidence with respect to the facilities and service authorizations that would be required in this event.

Consumers' also noted that at the time of the hearing, Indeck Corinth expected that the plant would start commercial operations by 1 November 1991. However, TransCanada

testified that transportation service would not be available until 1 April 1992. Consumers' wondered how gas would reach the plant between November 1991 and April 1992. In addition, Consumers' stated that if Empire were delayed beyond November 1991, there was no evidence about what backup transportation arrangements existed. Furthermore, Consumers' pointed out that although information on alternate or backstop arrangements was available for other potential shippers on Empire, similar information was not available for Indeck Corinth because the original application did not propose to use the Empire system.

With respect to other downstream transportation arrangements, Consumers' noted that in February 1990, Indeck Corinth expected to have a precedent agreement in place with CNG in March 1990, which later slipped to the second quarter of 1990, and by November 1990 Indeck Corinth advised that its precedent agreement with CNG was still under negotiation, and all that was available for the public record was a letter of intent. Consumers' went on to note that under these circumstances, it was still not known what the terms and conditions of any transportation arrangement would be, and whether such service would be available in a timely fashion. Consumers' also noted that the proposed CNG facilities were an alternative to Empire and, as a result, appeared to be caught up in the overall Empire dispute.

With respect to arrangements for transportation on Niagara Mohawk, Consumers' noted Indeck Corinth's statements that a precedent agreement was under negotiation with Niagara Mohawk, but that a problem existed with respect to ownership of compression equipment required to serve the cogeneration plant that prevented the agreement from being completed. Additionally, Niagara Mohawk would require new facilities for which an application to the NYSPSC had not yet been made, and a public hearing in this matter would be necessary. As of 15 November 1990, negotiations were still ongoing.

Indeck Corinth, in commenting on Consumers' objections, noted that the licence application is for the export of gas at Chippawa, Ontario and Indeck Services Corinth has a precedent agreement with National Fuel. Indeck Corinth stated that although the precedent agreement provides for an alternate transportation route, i.e. by National Fuel out of Niagara Falls via the Niagara Spur, should the precedent agreement with National Fuel be terminated, alternative arrangements would be made at that time and Indeck Corinth would apply for an amendment to its licence and bear the risk of that application. It was Indeck Corinth's view that this was an issue that would be dealt with if and when necessary.

With respect to other downstream transportation arrangements, Indeck Corinth pointed to CNG's "unequivocal" letter of intent to work with Indeck Services Corinth to arrange for transportation to the Corinth plant. With respect to Consumers' concern about not knowing the terms and conditions under which CNG would supply transportation service, Indeck Corinth relied on the fact that CNG was a FERC-regulated pipeline with published rates. At the same time Indeck Corinth acknowledged the fact that transportation agreements for the CNG and Niagara Mohawk systems were not available, but Indeck Corinth stated that it would not object to the licence being conditioned to require proof that the downstream transportation arrangements had been secured, although it did not see this as being necessary because a sunset clause would provide similar protection.

Consumers' noted that a financing commitment for the Corinth facility was originally expected in December 1989 with final financing anticipated in January 1990. Subsequently, Indeck Corinth testified that financing commitments were expected to be in place by early summer 1990. On 7 December 1990, Indeck Corinth advised that financing had not yet closed because the parties were awaiting the Board's decision on the tolling issue. Consumers' noted that the tolling issue came up in February 1990 and, as result, the resolution of this issue does not explain why financing was not secured in December 1989 as was originally expected. Indeck Corinth stated that the Board's ruling to proceed to make a decision on tolling methodology came after Indeck Corinth witnesses had testified in May 1990. Now that the Board's tolling decision has been released (GH-5-89, Volume 1 - Tolling and Economic Feasibility) Indeck Corinth has testified that financial closing for the project will occur by the end of the first quarter of 1991.

Consumers', in commenting on Indeck Corinth's forecasting track record, noted that during the course of the proceeding, evidence had been introduced to show that there had been significant changes with respect to the construction schedule of the Corinth plant. While construction was originally scheduled to commence in March 1990 with commercial operations commencing in November 1991, a lead time of 20 months, Indeck Corinth's most recent testimony was that construction was expected to commence in March or April 1991. Assuming the same lead time, Consumers' noted that commercial operations would not commence before December 1992, nine months after TransCanada would be able to offer transportation service to Indeck Corinth. Given this evidence, Consumers' voiced concern should these dates slip again.

Indeck Corinth held the view that it did have a strong track record, pointing specifically to its successful completion of the Oswego and Yerkes cogeneration projects for which export licences have already been issued. Noting that some of Indeck Corinth's arrangements were more advanced than others, it was Indeck Corinth's position that the Board should adopt a somewhat flexible attitude and recognize the realities and complexities of dealing with numerous contracting parties and regulatory authorities. Indeck Corinth also stated that, in any event, the inclusion of a sunset clause in the licence and conditions in the facilities certificate, such as those imposed in GH-1-89, would protect the Canadian public interest.

Consumers' expressed its concern that only a letter of intent to wheel the power from the Corinth facility to Con Ed had been filed with the Board, with the inference that the wheeling agreement had not yet been executed. In reply to Consumers' concerns, Indeck Corinth stated that it had a letter of intent dated 24 October 1988 between Niagara Mohawk and Indeck Services Corinth, and that it intended to enter into a long-term wheeling agreement.

9.5 Views of the Board

Although modest deficiencies in productive capacity relative to requirements exist over the greater part of the proposed term of the export, the Board is generally satisfied with Indeck Corinth's supply position. The Board notes that Indeck Corinth's gas supply contracts contain covenants that allow its producers to dedicate additional reserves to the performance of the contract and require them to provide Indeck Corinth with an assurance of a certain performance level throughout the export term. Further, Indeck Corinth's producers are required to cover any additional costs incurred by Indeck Corinth in the event that a producer fails to deliver its contract quantity.

The Board is satisfied with the downstream markets for the electricity and steam produced by the cogeneration facility and that the facility would operate at a high load factor. However, with respect to the sale of electricity, the Board notes that a wheeling agreement has not yet been executed. The Board expects that such an agreement would have to be signed prior to the commencement of gas exports. The Board notes that project financing and DOE/FE import authorization have not yet been received but, given the evidence before it, does not view this as a major impediment. The Board also notes the cogeneration facility's expected completion date of December 1992.

The Board notes that transportation has been arranged on all required Canadian pipelines, but that precedent agreements with respect to transportation on CNG and Niagara Mohawk are in the negotiation stage. The Board is satisfied that the proposed export will recover transportation costs incurred in Canada in view of the fact that Indeck Corinth has agreed to pay all demand charges associated with transporting the gas to the international border.

With respect to assurance of take, the Board believes that there will be a high level of take in view of the minimum annual obligation on a take-or-pay basis in each of the agreements, Indeck Corinth's liability to pay for demand charges and the market-sensitivity of the price.

The Board has reviewed the gas contracts and has noted that they have been negotiated at arm's length, and that the pricing terms are such that the arrangement is likely to be durable over the contract/licence term.

Producer support was demonstrated by the fact that the Alberta producers have executed contracts with Indeck Corinth.

9.6 Decision

The Board has decided to issue a gas export licence to Indeck Corinth, subject to the approval of the Governor in Council. Appendix IV contains the terms and conditions of the licence, including a condition that the term of the licence shall commence on the later of 1 November 1991 or the date of first deliveries and shall end on 1 November 1993, unless exports have commenced under the licence on or before 1 November 1993, in which case the term would end 15 years following the later of 1 November 1991 or the date of first deliveries.

Chapter 10

Indeck Gas Supply Corporation - Indeck-Ilion

10.1 Application Summary

In an application dated 30 November 1989, as amended, Indeck-Ilion by its agent Northstar, sought, pursuant to Part VI of the Act, a natural gas export licence. The gas would be sold to Indeck Energy Services of Ilion, Inc. ("Indeck-Services-Ilion").

The proposed export volumes would be produced from established reserves in Alberta controlled by Trilogy Resource Corporation ("Trilogy").

Niagara Mohawk would purchase the electricity and E.I. DuPont de Nemours and Company, Inc. ("DuPont") would purchase the steam.

Indeck-Ilion applied for a licence with the following terms and conditions:

Term	- Later of 1 November 1991 or the date of first deliveries, for a period of 15 years
Point of Export	- near Chippawa, Ontario
Maximum Daily Quantity	- 210 10^3m^3 (7.5 MMcf)
Maximum Annual Quantity	- 73 10^6m^3 (2.6 Bcf)
Maximum Term Quantity	- 852 10^6m^3 (30.2 Bcf)
Tolerances	- 10 percent per day and 2 percent per month

10.2 Gas Supply

10.2.1 Supply Contracts

Indeck-Ilion has executed a gas supply contract (the expected term of the agreement is 13 years, with a maximum term of 18 years) with Trilogy. Trilogy has dedicated reserves from fields under its control within Alberta to satisfy the regulatory requirements for the export but has not contractually committed these reserves to Indeck-Ilion.

The contract required Indeck-Ilion to make a lump-sum payment to Trilogy for the contracted volumes. In turn, Trilogy was to provide Indeck-Ilion with an irrevocable letter of credit to secure its obligation to deliver the remaining volumes. The letter of credit would be increased or decreased to match the unconsumed entitlement over the term of the contract.

These contractual arrangements are discussed further in section 10.3.3 of these Reasons.

10.2.2 Reserves

Table 10-1 shows that the Board's estimate of Indeck-Ilion's established gas reserves is ten percent lower than Indeck-Ilion's estimate and two percent lower than the applied-for volume.

The variance between Indeck-Ilion's and the Board's estimates of reserves can be primarily attributed to differences in interpretation of average net pay for the Glauconite pool in the Bigoray field.

Indeck-Ilion used wellbore net pay thicknesses of eight to ten metres to calculate gas reservoir volumes. The Board mapped the zone and calculated the pool average net pay to be about six metres. The lower net pay estimate for the Glauconite pool accounted for the majority of the overall difference in the estimates of remaining reserves. The Board's estimate of Indeck-Ilion's contracted reserves in the Glauconite pool is 17 percent lower than Indeck-Ilion's estimate.

Indeck-Ilion assigned full-section drainage to both of their single-well pools, allocating a portion of the area in one of the wells to probable reserves. It also assigned a full section of probable reserves in a second zone in one of the above wells. A discount factor was applied to both probable estimates. Indeck-Ilion noted, based on comments from its consultants, that it employed areas of 256

Table 10-1

Comparison of Estimates of Indeck-Ilion's Established Gas Reserves With the Applied-for Volume

$10^6 m^3$(Bcf)

Indeck-Ilion[1]	NEB[2]	Applied-for Volume
926 (32.7)	838 (29.6)	852 (30.1)

1. As of 1 September 1989 and 1 November 1991 (no production is anticipated by Indeck-Ilion prior to 1 November 1991).
2. As of 31 December 1988.

hectares for correlatable sediments in determining reserve estimates for single-well pools where other limiting evidence was not available. It further noted, however, that when other types of sediments (point bars, etc.) and other limiting factors are considered for all single-well pools, an overall average area significantly less than 256 hectares would be calculated.

The Board assigned slightly greater reserves to the Indeck-Ilion single-well pools in total than the reserves calculated by Indeck-Ilion. The difference is primarily due to a more optimistic treatment of probable reserves for certain of these pools.

In its analysis of Indeck-Ilion's gas supply, the Board recognized nine gas pools, the majority of which are not producing. Most of the pools are relatively small and located in the west-central portion of Alberta in Cretaceous zones. Sixty-seven percent of the pools for which Indeck-Ilion submitted reserves have reserves estimated by the Board to be less than 100 $10^6 m^3$ (3.5 Bcf) of initial marketable gas.

In summary, the Board's estimate is marginally lower than both Indeck-Ilion's estimate and the applied-for volume. This difference is related primarily to interpretation of average net pay for the Glauconite pool in the Bigoray field.

10.2.3 Productive Capacity

A comparison of the Board's and Indeck-Ilion's estimates of productive capacity with the applied-for requirements is shown in Figure 10.1.

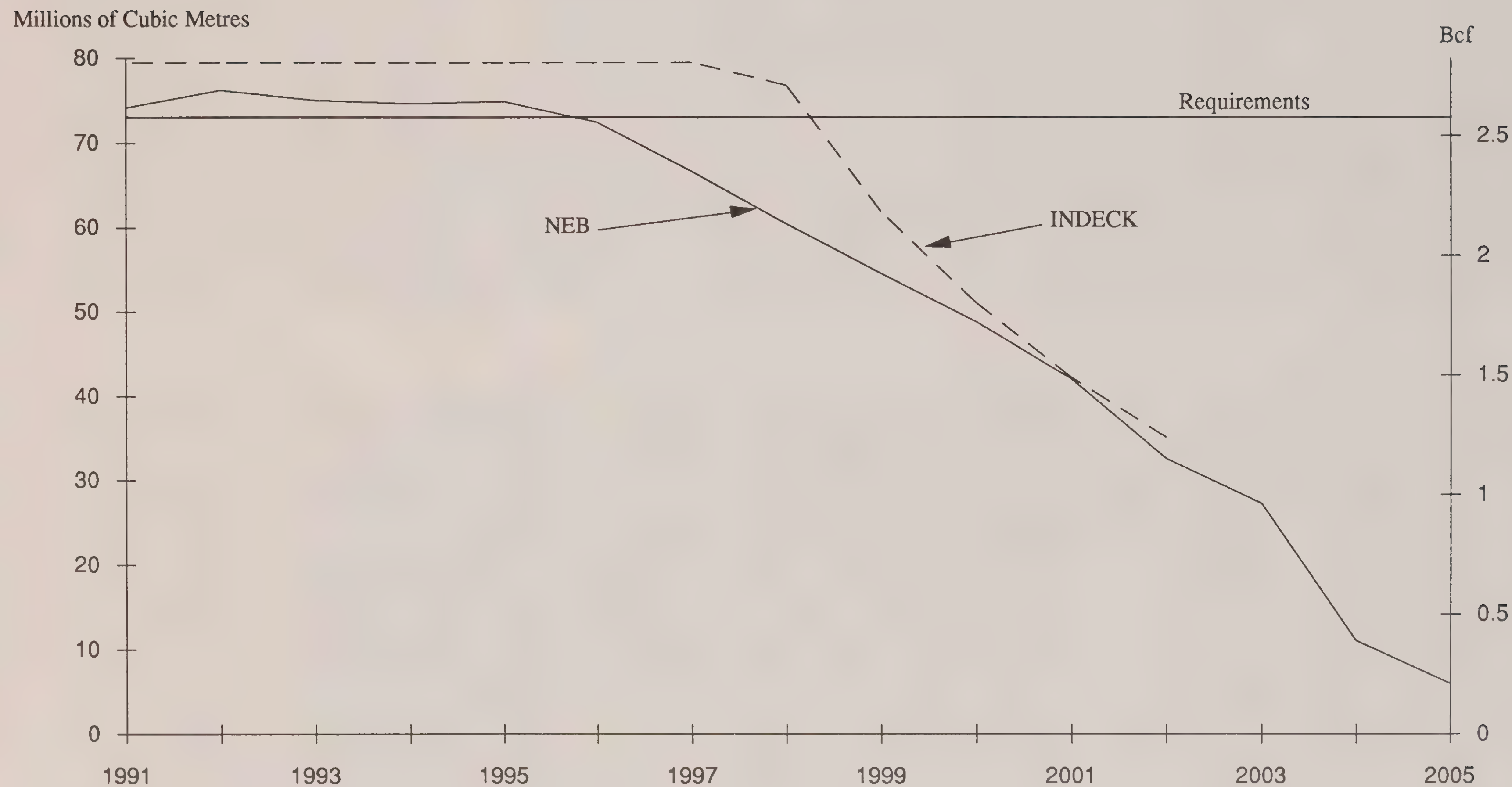
Indeck-Ilion provided a 12-year forecast of productive capacity that showed it capable of meeting the applied-for requirements until 1998, with increasing shortfalls thereafter.

Trilogy, Indeck-Ilion's supplier, indicated that it would endeavour to maintain the required deliverability rate through either further development of its existing areas or the addition of reserves from other areas under its control. In support of this, Trilogy provided a schedule of development for its existing areas showing the drilling and compression that it anticipated would maintain the required deliverability. Indeck-Ilion submitted that the up front lump-sum payment provided for in the contract would enable Trilogy to engage in further exploration and development of reserves.

Trilogy also provided a summary of its corporate reserves situation for the past five years that indicated that its net additions equalled 2.8 times its production. Trilogy noted that its contract with Indeck-Ilion represents only 20.9 percent of its total reserves and it anticipates that with the

Figure 10.1

COMPARISON OF ESTIMATES OF ANNUAL PRODUCTIVE CAPACITY FOR INDECK-ILION



higher investment levels resulting from this contract, reserves additions in excess of 4 249 $10^6 m^3$ (151 Bcf) and additional production in the order of 1 416 $10^3 m^3/d$ (50 MMcfd) can be expected over the next five years.

The Board's projection of productive capacity is very similar to that of Indeck-Ilion and indicates deficiencies in supply beginning in 1996.

10.3 Market and Commercial Arrangements and Regulatory Status

10.3.1 Market

The 54.7 MW Ilion cogeneration plant, expected to be in commercial operation by December 1992, will be located at a site sold by DuPont to Ilion, near the DuPont Remington Arms Plant. The steam will be used for heating and for cleaning components during metallurgical processing. The cogeneration plant will provide Niagara Mohawk with an electrical energy output of approximately 460,000 MW.h annually. Niagara Mohawk provides electrical service to residential, commercial and industrial customers in New York State including the cities of Albany, Buffalo, Syracuse, and Watertown.

The Applicant stated that although it had been delayed because of the Board's tolling decision, financing for the project was expected to be in place by the end of the first quarter of 1991.

Indeck-Ilion testified that the minimum operating load factor is forecasted to be 94 percent during each year of the term of the proposed licence. Given Indeck-Ilion's ability to divert gas to other cogeneration facilities, it expects that the actual load factor will be close to 100 percent. The Applicant stated that the gas proposed for export would represent approximately 58 percent of the total gas requirements of the cogeneration facility.

10.3.2 Transportation

The route by which the gas proposed for export by Indeck-Ilion would be shipped is identical to that which was described for Indeck Corinth in section 9.3.2.

Within Alberta, Trilogy has requested firm, long-term transportation service from NOVA to deliver the proposed export volumes to Empress, Alberta. The arrangements for the transportation of the gas from Empress to Chippawa, Ontario on TransCanada were the subject of an application under section 71 of the Act. Indeck-Ilion would be responsible for the payment of all related transportation costs on the TransCanada system.

In the U.S., the status of transportation arrangements with National Fuel and CNG are described in section 9.3.2. From the Ilion city gate, Niagara Mohawk would deliver the gas to the cogeneration facility through a one-mile pipeline extension. Indeck-Services-Ilion and Niagara Mohawk have entered into an agreement in principle dated 12 January 1990 for this aspect of the transportation.

10.3.3 Gas Sales Contract

In its role as the party responsible for acquiring natural gas supplies, Indeck-Ilion executed a gas sales and purchase agreement with Trilogy dated 18 May 1990. In turn, Indeck-Ilion concluded a gas purchase agreement dated 10 October 1989 with Indeck-Services-Ilion, under which the latter agrees to pay the costs incurred by Indeck-Ilion to acquire the gas in Alberta and to transport the volumes to Chippawa, Ontario.

The terms and conditions of the contract governing the export of the gas are essentially those included in the gas sales and purchase agreement between Indeck-Ilion and Trilogy. This arrangement is for a volume of 225 $10^3 m^3$ (8.0 MMcf) per day.

The agreement includes a number of conditions precedent. Trilogy is responsible for obtaining a provincial removal permit and for arranging firm transportation on NOVA. Indeck-Ilion is responsible for obtaining an NEB export licence and a U.S. import permit and for concluding transportation arrangements from Empress to Chippawa and, through agreement with Indeck-Services-Ilion, from the international boundary to Ilion. All conditions must be satisfied by 1 November 1991, otherwise the agreement may be terminated by either party on ten days notice. The arrangement may also be terminated at the option of Trilogy prior to 1 February 1991, if

Indeck-Ilion has not made its lump-sum payment to Trilogy (for description, see below) on or before this date. If deliveries of gas have not occurred prior to 1 November 1995, either party may terminate the contract.

The gas sales and purchase agreement will become effective on 1 November 1991 and remain in effect for no more than 18 years, depending on the rate-of-take. Trilogy is committed to make available to Indeck-Ilion a maximum daily quantity of 225 10^3m^3 (8.0 MMcf) and a maximum annual quantity of 77.5 10^6m^3 (2.8 Bcf), the latter quantity reflecting an assumed regularly scheduled outage of 21 days per year (defined as a scheduled plant shutdown for routine inspection, maintenance and repair). Indeck-Ilion undertakes to purchase and use at its cogeneration facility a minimum daily quantity of 197 10^3m^3 (7.0 MMcf). The maximum entitlement to Indeck-Ilion under the terms of the agreement is 916 10^6m^3 (32.5 Bcf), which must be taken by the end of the eighteenth year or it is forfeited.

Under the pricing provisions of the agreement, while Trilogy is responsible for arranging the firm transportation on NOVA, Indeck-Ilion is committed to pay the demand charge. Indeck-Ilion is also responsible for paying the demand charge on TransCanada while Indeck-Services-Ilion has responsibility for the transportation costs downstream of the international boundary.

The price to be paid by Indeck-Ilion to Trilogy will consist of the following:

a. a single, up-front, lump-sum payment of $ U.S. 19 987 500;

b. an operating fee of $ U.S. 0.24/GJ ($ U.S. 0.25/MMBtu) for 1991, with escalation of five percent annually for subsequent years;

c. reimbursement of all Crown royalties paid by Trilogy on the gas delivered; and

d. payment of the demand charge on NOVA.

With respect to the lump-sum payment, Indeck-Ilion testified that it was paid on 5 December 1990. Trilogy was to provide Indeck-Ilion with an irrevocable letter of credit to secure its obligation to deliver the remaining volumes. The letter of credit is increased or decreased to match the unconsumed entitlement throughout the term.

10.3.4 Power Sales Contract

The proposed sale of electricity from the Ilion cogeneration plant will be pursuant to the second amendment to the power sale contract, dated 23 May 1990 between Niagara Mohawk and Indeck-Services-Ilion. The contract includes automatic successive one-year renewals during the 20-year period from the commercial operation date. After 20 years the contract will be renewed for successive one-year terms until terminated by either party.

The Ilion cogeneration plant would be dispatched daily by Niagara Mohawk based on economic criteria. The price to be paid for the electrical output from the plant reflects a negotiated base price for capacity, energy, transportation and operation and maintenance. Except for energy payments, all payments are based on the dependable maximum net capability determined in accordance with the New York power pool operating agreement. All the rates include escalation factors. Capacity is escalated through year 15, thereafter it is a fixed rate. The electricity sold from the Ilion facility does not require wheeling by third parties.

10.3.5 Thermal Energy Sales Agreement

The proposed sale of thermal energy from the Ilion plant will be pursuant to a steam purchase agreement dated 17 November 1989 between Indeck-Services-Ilion and DuPont. The agreement will continue for a period of 20 years commencing with the initial delivery date and will remain in effect thereafter unless terminated upon three years notice by either party prior to the end of the initial term or any time thereafter. DuPont is obliged to purchase sufficient thermal energy to enable the cogeneration facility to maintain its QF status. DuPont's steam requirement varies throughout the year, with the June to September period being the lowest. If the steam take is too low, the steam take will be negotiated upward, so as to maintain QF status. If DuPont should not purchase sufficient steam, then the cogeneration plant may contract to sell

thermal energy to another purchaser to maintain the facility's QF status. If DuPont ceases operation, Indeck-Services-Ilion can attempt to conduct an affiliated thermal consuming business on vacant land or within vacant structures purchased from DuPont for one dollar. The agreement provides for the possible reconditioning of DuPont's standby boiler facility, if required. The price of steam was not included in the agreement because DuPont had not consented to publish steam prices.

10.3.6 Regulatory Status

Indeck-Ilion applied to the AERCB on 15 December 1989 for a long-term energy removal permit. The application specified a term of 15 years and a term volume of 3 538 $10^6 m^3$ (124.9 Bcf), which includes the Indeck Corinth volumes (see section 9.3.6). Approval is expected in the spring of 1991.

Indeck-Services-Ilion applied for DOE/FE import authorization on 22 January 1990. No objections have been filed and approval is expected in May 1991.

The facility has received FERC QF status.

10.4 Views of Intervenors

Consumers', for the same reasons used with respect to the Indeck Corinth application, objected to the Indeck-Ilion proposed export on the basis of the downstream transportation arrangements. For a description of Consumers' concerns and Indeck's responses, see section 9.4 of these Reasons.

Consumers' noted that the original purchaser of power from the Ilion facility was Con Ed under a must-run contract, and that subsequently the power purchase agreement was taken over by Niagara Mohawk, with the agreement amended to make the Ilion facility dispatchable by Niagara Mohawk. Consumers' stated that there was almost no evidence on the effect of the amendment from must-run to dispatchable status on the operation or economics of the project. Indeck-Ilion stated that the facility would be dispatched on-line, whenever it was available for dispatch, based on a comparison of the facility's variable energy price using NYSPSC 1988 long-run, average cost ("LRAC") assumptions, comparing favourably with Niagara Mohawk's marginal price. Indeck-Ilion stated that a comparison of its variable price with Niagara Mohawk's marginal price would result in five periods of one to five hours duration in 1992 when the facility's variable price exceeds Niagara Mohawk's marginal cost and that because of 24-hour minimum run times and start-up charges included in the power purchase agreement, it was expected that the plant would not be dispatched off-line. Indeck-Ilion also pointed to the agreement of the NYSPSC that the plant will be dispatchable whenever it is available in 1992 and thereafter for each year for the term of the power purchase agreement.

The second amendment to the power sale contract requires approval of the NYSPSC. The Applicant has undertaken to notify the Board of NYSPSC approval.

10.5 Views of the Board

The Board's analysis of Indeck-Ilion's gas supply indicates deficiencies, minor in the case of reserves and more significant in the case of productive capacity, relative to the applied-for requirements. However the gas supply contract with Trilogy provided an up front, lump-sum payment for Indeck-Ilion's gas supply. The Board believes that this lump-sum payment, along with the performance covenants in the contract, provide an adequate degree of assurance that the required supply will be made available by Trilogy.

The Board is therefore satisfied with the adequacy of Indeck-Ilion's supply relative to the requirements in the application.

The Board is satisfied that the downstream markets for the electricity and steam produced by the cogeneration facility are secure and that the facility would operate at a high load factor. The Board notes that project financing and DOE/FE import authorization have not yet been received. The Board also notes the cogeneration facility's expected completion date of December 1992.

The Board notes that transportation has been arranged on all required pipelines, and is satisfied that the proposed export will recover transportation costs incurred in Canada in view of

the fact that Indeck-Ilion is required to reimburse Trilogy for NOVA transportation costs and Indeck-Ilion will be responsible for TransCanada transportation charges if service is made available.

The agreement between Indeck-Ilion and Trilogy provides for an up-front lump-sum payment of almost $ U.S. 20 million which, the Board notes, has already been paid. The contract also provides for the reimbursement of all Crown royalties paid by Trilogy on the gas delivered as well as the payment of an operating fee which will escalate five percent on an annual basis, starting in 1992. In addition, the NOVA demand charges will be paid. The Board concurs with Indeck-Ilion's view that the provisions of the contract permit adjustments to reflect changing market conditions over the life of the contract.

The Board has reviewed the gas sales contracts and notes that they have been negotiated at arm's length.

Trilogy's execution of a contract with Indeck-Ilion is clear evidence of producer support for the proposed export.

The Board notes Consumers' objections to issuing Indeck-Ilion an export licence on the basis that certain contract arrangements had changed (i.e. the power purchase agreement) and some regulatory authorizations and downstream transportation arrangements were missing. While there is uncertainty as to the final disposition of the matter of the Empire State Pipeline, the Board notes that Indeck-Ilion does have an executed precedent agreement with National Fuel. As to the transportation arrangements with CNG, although there has been considerable delay in finalizing this particular aspect of the downstream transportation arrangements, the Board is satisfied that this matter will be resolved in view of CNG's expressed intention to work with Indeck-Ilion to resolve this matter.

Finally, with the inclusion of a sunset clause in the licence, the Board holds the view that the public interest will be protected if these matters are not resolved in a timely fashion.

10.6 Decision

The Board has decided to issue a gas export licence to Indeck-Ilion, subject to the approval of the Governor in Council. Appendix IV contains the terms and conditions of the licence, including a condition that the term of the licence shall commence on the later of 1 November 1991 or the date of first deliveries and shall end on 1 November 1993, unless exports have commenced under the licence on or before 1 November 1993, in which case the term would end 15 years following the later of 1 November 1991 or the date of first deliveries.

Chapter 11

JMC Selkirk, Inc.

11.1 Application Summary

By application dated 11 August 1989, JMC Selkirk, as General Partner of Selkirk Cogeneration Partners, L.P. ("Selkirk"), sought, pursuant to Part VI of the Act, a natural gas export licence with the following terms and conditions:

Term	- commencing on the later of 1 November 1991 or the date of first deliveries for a term of 15 years and 6 months
Point of Export	- near Iroquois, Ontario
Maximum Daily Quantity	- 652 10^3m^3 (23.0 MMcf)
Maximum Annual Quantity	- 238 10^6m^3 (8.4 Bcf)
Maximum Term Quantity	- 3 686 10^6m^3 (130.1 Bcf)
Tolerances	- 10 percent per day and 2 percent per year

The gas proposed for export would be produced in Alberta and the Northwest Territories from existing reserves controlled by Paramount Resources Ltd. ("Paramount"). The reserves in the Northwest Territories are located adjacent to the Alberta border and would be connected to the NOVA system.

The gas would be transported on NOVA and TransCanada to the IGTS inlet near Iroquois, Ontario. IGTS and Tennessee would then ship the gas to Selkirk's cogeneration facility at Selkirk, New York.

The cogeneration facility's power output would be sold to Niagara Mohawk and its thermal energy to the adjacent General Electric Company ("G.E.") Plastics Division plant.

11.2 Gas Supply

11.2.1 Supply Contracts

Selkirk has executed a contract with Paramount for a period of 15 years, with an option for an additional five years.

Paramount has contractually dedicated reserves to Selkirk. Paramount is required to provide an engineering report demonstrating that it has dedicated reserves equal to the applied-for volumes. Each year thereafter, Paramount must provide a report demonstrating that sufficient remaining reserves exist to maintain deliverability equal to the MDQ for five years. If the report shows the reserves are not sufficient to maintain this rate, Paramount must dedicate additional reserves to the performance of the contract.

Provisions within the contract stipulate that Paramount will be the sole supplier to the project, up to the MDQ, throughout the term of the contract.

These contractual arrangements are discussed further in section 11.3.3 of these Reasons.

11.2.2 Reserves

The Board's estimate of established gas reserves and undiscovered potential is 19 percent lower than Selkirk's estimate, but 34 percent higher than the applied-for volume, as shown in Table 11-1.

The Board's estimate includes undiscovered potential, which amounts to approximately ten percent of the Board's total estimate.

The Selkirk estimate of established reserves includes estimates of reserves for confidential wells. Supporting information for the estimates for confidential wells are not available to the

Table 11-1

Comparison of Estimates of Selkirk's Established Gas Reserves and Undiscovered Potential With the Applied-for Volume

$10^6 m^3$ (Bcf)

	Selkirk[1]	NEB[2]	Applied-for Volume
Established Reserves	6 069 (214)	4 450 (157)	3 686 (130)
Undiscovered Potential	473 (17)		
Total	6 069 (214)	4 923 (174)	3 686 (130)

1. As of 1 February 1990.
2. As of 31 December 1988.

Board and these estimates have therefore been classified as undiscovered potential and discounted appropriately by the Board in assessing Selkirk's supply. The discrepancy in estimates of established reserves between Selkirk and the Board can be largely attributed to differences in area and net pay estimates and the risk factor used in discounting probable reserves in three areas. These areas are Kettle River, Liege South and Saleski. There is also a divergence due to the cumulative effect of other small variances in individual pools and from inclusion of reserves for confidential wells in this category.

Within the McMurray Formation in the Kettle River area, Selkirk mapped five multi-well pools. Selkirk stated that sand is present in many of the 112 wells drilled in the area. Selkirk further provided gas/water interface and pressure data to support its mapping and noted that production performance data from wells in the adjacent Chard pool suggests drainage in excess of one section which lends support to its mapping techniques in Kettle River. Selkirk did note, however, that higher risk areas were not included in the mapping of the five pools.

The Board's estimate of reserves for the Kettle River area was lower than Selkirk's estimate by 286 $10^6 m^3$ (10.0 Bcf). The Kettle River estimate of reserves by Selkirk included broad areas with limited well control, especially in the McMurray 12-29 and Clearwater 11-19 pools. The Board's evaluation of the McMurray 12-29 pool was somewhat different than that of Selkirk, resulting in the exclusion of some undrilled sections and the contouring of net pays in a somewhat more conservative manner than submitted by Selkirk. Although the Board's and Selkirk's individual wells net pay estimates were generally in agreement, the Board's overall assessment resulted in a somewhat lower estimate of reserves.

Within the Clearwater Formation in the Kettle River area, Selkirk mapped one large pool of approximately 4 100 hectares, designated the Clearwater 11-19 pool. The Board's evaluation of the Clearwater 11-19 pool yielded a proven area of 770 hectares, generally in the eastern portion of

the pool. The Board's review of wells and tests in and adjacent to the remaining pool area mapped by Selkirk suggested minimal likelihood of gas. The Board does not, at this time, recognize reserves for all of the area mapped by Selkirk.

Selkirk included reserves from two Liege South (west leg) pools, one in the Wabiskaw and another in the Middle Wabiskaw, as part of its gas supply. The Board's estimate of reserves for the above pools is 72 10^6m^3 (2.5 Bcf) lower than Selkirk's estimate of 323 10^6m^3 (11.4 Bcf). The difference is primarily due to the inclusion of a number of undrilled sections by Selkirk which the Board does not fully recognize at this time.

Selkirk's gas supply includes reserves assigned to two full sections of land on the southeastern edge of the Saleski Grosmont A pool. The Board used its own estimate of reserves for the Grosmont A pool and allocated a portion of the pool reserves to Selkirk. This resulted in an estimate of reserves that is 144 10^6m^3 (5.1 Bcf) lower than Selkirk's estimate.

Selkirk provided an estimate of reserves of 946 10^6m^3 (33.4 Bcf) for the confidential wells in several Alberta pools and in Cameron Hills. This estimate was provided by an independent consultant with access to the available data. The Board was not able to analyze supporting data for these estimates due to their confidential nature at this time. The Board therefore assigned the wells to the potential category. The Selkirk estimate was then discounted by a risk factor to result in a potential estimate of 473 10^6m^3 (16.7 Bcf). The difference between the two estimates is, therefore, due to the risk discounting and is approximately 41 percent of the overall difference in estimates between Selkirk and the Board. The Board, in discounting the potential, recognizes that this is a more severe assessment than may be appropriate once the relevant supporting data becomes available.

The Board's analysis recognized 83 pools, of which 90 percent are not yet on production. The majority of the pools are located in northeast Alberta in Cretaceous sands, while the remainder are in the Cameron Hills area of north-central Alberta and southwest Northwest Territories. Eighty percent of the pools for which Selkirk submitted reserves have reserves estimated by the Board to be less than 100 10^6m^3 (3.5 Bcf) of initial marketable gas.

In summary, the Board's estimate of reserves is lower than Selkirk's estimate but higher than the applied-for volume. This is due primarily to differences in mapped area, net pay, the cumulative effect of small variances for several pools, and differences in the treatment of wells for which the supporting information remains confidential.

11.2.3 Productive Capacity

A comparison of the Board's and Selkirk's projections of productive capacity with the applied-for requirements is shown in Figure 11.1.

Selkirk provided an estimate of productive capacity from its dedicated reserves that showed it capable of maintaining productive capacity in excess of requirements throughout the term of the proposed export licence. This projection was based upon its schedule of future development and connections.

The Board's estimate of productive capacity shows that Selkirk is capable of meeting its requirements until 2002, but that increasing shortfalls are anticipated thereafter. The Board's projection generally was based on Selkirk's connection schedule, with the exception of some of the 1994 connections, which were moved forward to alleviate shortfalls resulting from the Board's lower estimate of reserves.

11.3 Market and Commercial Arrangements and Regulatory Status

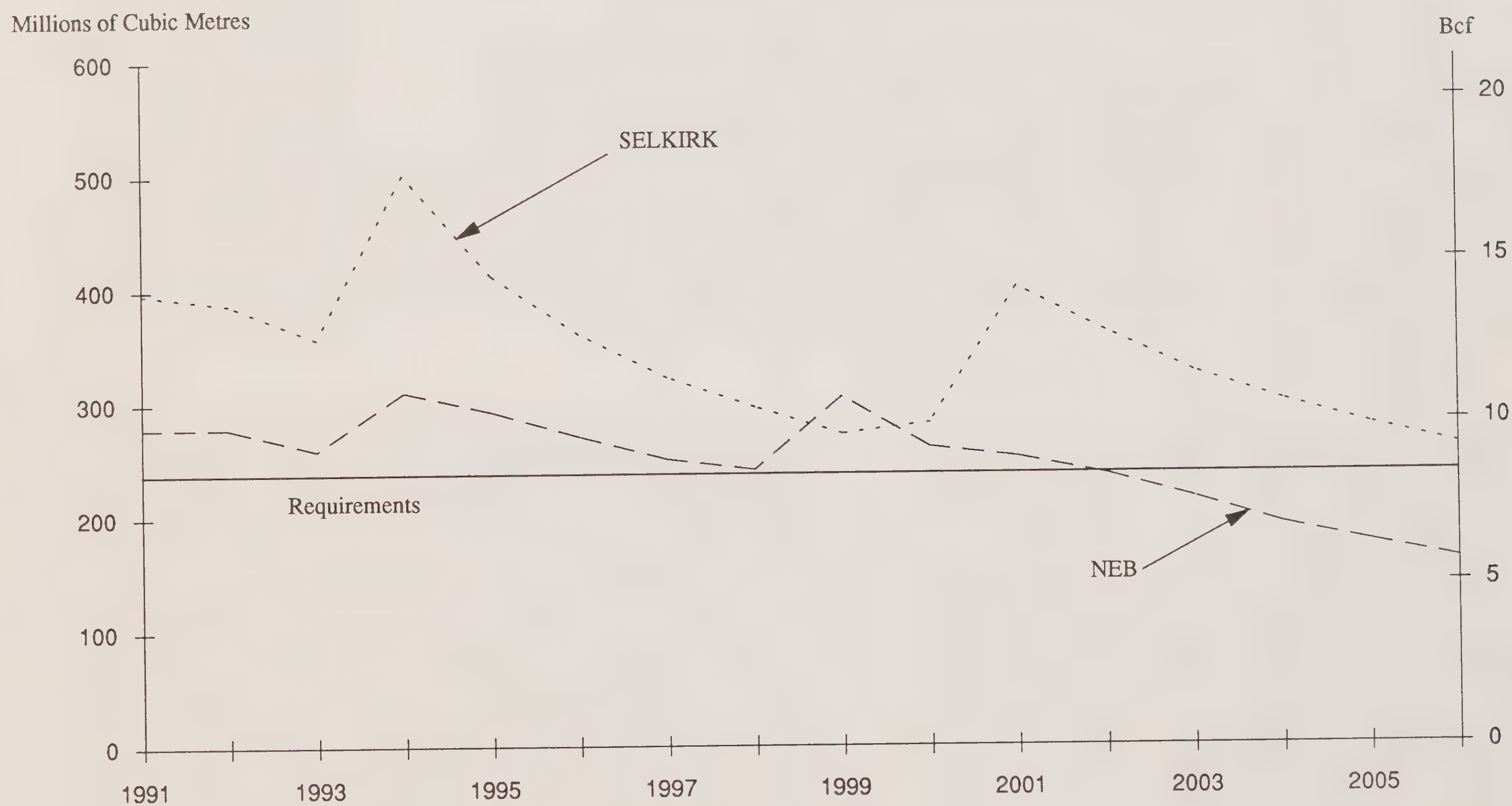
11.3.1 Market

The gas proposed for export would be used to fuel a 79.9 MW gas-fired combined-cycle cogeneration facility that Selkirk plans to construct on land leased from G.E. at Selkirk, New York.

Selkirk is comprised of a development subsidiary of J. Makowski Associates, Inc. ("JMAI") and Old State Management. JMAI has been involved in several projects involving export licences and corresponding pipeline capacity that have

Figure 11.1

COMPARISON OF ESTIMATES OF ANNUAL PRODUCTIVE CAPACITY FOR SELKIRK



previously been considered and approved by the Board.

The G.E. plant manufactures the plastic product Noryl, which is utilized in automobile manufacture. The cogeneration plant is expected to provide Niagara Mohawk with approximately 625,000 MW.h of energy annually. Niagara Mohawk provides electrical service to residential, commercial and industrial customers in New York State. The utility's major markets are in the cities of Albany, Buffalo, Syracuse, and Watertown.

Selkirk has entered into a backstopping agreement with Distrigas for regasified liquefied natural gas. The project also plans to utilize waste gas, produced in G.E.'s manufacturing process, and to be capable of operating on No. 2 fuel oil, propane and butane as back-up fuels. Otherwise, the cogeneration facility would be fuelled entirely by the applied-for volumes.

Project financing was finalized with a consortium of banks, led by Chase Manhattan Bank, on 19 June 1990. Construction of the cogeneration facility by Bechtel Construction Company commenced following the project's financial closing, with all required construction and operation approvals and permits in the U.S. having been obtained. The plant is expected to be in commercial operation in January 1992.

Based upon simulations of the New York Power Pool performed by Energy Management Associates, Inc.'s PROMOD III model, it was submitted that the cogeneration facility would be a base-load facility and that it would operate at a load factor exceeding 88 percent.

A second phase of the Selkirk project is contemplated but detailed plans have not yet been completed. Selkirk intends to incorporate Phase II with Phase I and to apply for QF recertification as an improved project.

11.3.2 Transportation

Within Alberta, the gas would be shipped to Empress on the NOVA system. TransCanada would then transport the gas to IGTS for delivery onto the Tennessee system. Tennessee would transport the gas to the cogeneration facility in Selkirk, New York.

Transportation in Alberta for 620 10^3m^3/d (21.9 MMcfd) of gas has been secured under a 15-year firm service agreement between NOVA and Paramount. Paramount has requested additional capacity on NOVA and has been advised that such capacity would be available commencing 1 November 1991.

Selkirk and TransCanada entered into a precedent agreement dated 1 May 1989, as amended, for firm transportation of the full export volume. The service term would commence no earlier than 1 November 1991 and end on 31 October 2011. Under the terms of a novation agreement dated 20 April 1990, Selkirk assigned its interest in the precedent agreement with TransCanada to Selkirk . Selkirk is thus directly responsible for the payment of demand charges on TransCanada.

Selkirk secured firm service on IGTS and Tennessee under precedent agreements dated 1 June 1990 and 16 December 1988 respectively. FERC approval of facilities additions required on these two pipelines was granted on 14 November 1990.

The 3.4 kilometre (2.1-mile) pipeline interconnect between Tennessee's system and the cogeneration facility is owned and operated by Selkirk Partners. The interconnect has been approved by the NYSPSC and has already been constructed.

11.3.3 Gas Sales Contract

A gas sales contract dated 15 December 1989 has been executed by Paramount and Selkirk. The contract term extends for 15 years following the commencement of firm deliveries and provides for an initial six-month test period. The contract includes provision for the buyer to extend the term by five years subject to certain conditions protecting Paramount.

The contract provides for the daily delivery of up to 652 10^3m^3 (23 MMcf) of gas at Empress, Alberta. At Selkirk's request, Paramount is to use best efforts to provide up to this volume during the cogeneration facility's test period.

The contract is subject to construction of the cogeneration facility commencing 31 December 1990, or other such mutually agreed upon date, and the NEB not prescribing incremental tolls on TransCanada.

The contract explicitly prohibits Selkirk from entering into long-term gas supply contracts with parties other than Paramount. Further, should less than the full MDQ be nominated on any day, then Paramount has the option to use Selkirk's unutilized transportation rights to market such gas.

The contract includes a two-part pricing structure consisting of a demand charge and a commodity charge.

The monthly demand charge component is the product of the MDQ averaged over the month and the monthly per unit demand charge paid by Paramount for deliveries by NOVA to Empress in that month.

The commodity charge component will be adjusted monthly starting from an initial level of $ U.S. 1.49/GJ ($ U.S. 1.60/MMBtu) effective 21 December 1988. Adjustments to the commodity charge will be based on changes in a fossil fuel index comprised of the gas cost component of CNG's requirements service ("RQ") rate schedule and of No. 6 spot cargo fuel oil at New York Harbour. Niagara Mohawk's actual fuel use will be used for the purposes of weighting the index fuels (natural gas and No. 6 fuel oil) in the fossil fuel index price. Contractually, coal is excluded from the index and natural gas cannot be assigned a weight of less than one-third.

Selkirk submitted that as of 1 January 1990, the Alberta border price would have been $ Cdn. 2.18/GJ ($ Cdn. 2.30/MMBtu). Selkirk estimated that from 1988 to 2006 inclusive, the commodity charge component of the price would increase by 5.8 and 7.5 percent respectively under the low and high oil price scenarios contained in the Board's report, Canadian Energy Supply and Demand 1987 - 2005.

The contract allows for yearly renegotiation of the contractual pricing provisions, excluding demand charges. If renegotiation is unsuccessful, then either party may request arbitration. The purpose of arbitration would be to set a commodity charge comparable to average netbacks received by Alberta producers under comparable long-term contracts, provided that such a commodity charge would likely result in the cogeneration facility being dispatched approximately 310 days per year.

11.3.4 Power Sales Agreement

The proposed sale of electricity from the cogeneration plant would be pursuant to the agreement dated 7 December 1987, as amended, between Selkirk and Niagara Mohawk. The agreement continues for a period of 20 years from the initial operation date.

The cogeneration plant would be dispatched by Niagara Mohawk based on economic criteria. Under the agreement, parties have waived avoided cost and negotiated the price of electricity. If Niagara Mohawk directs the plant to depart from its scheduled operation, the utility is required to pay additional charges. Should the cogeneration plant lose its QF certification, the rates specified in the agreement would be adjusted downward by 15 percent. Capacity charges are payable, whether or not Niagara Mohawk dispatches the plant. The sale of electricity from the facility does not require wheeling by third parties.

Selkirk may terminate the agreement at any time upon two years written notice. If the contract is terminated, Selkirk, in addition to a termination fee, would be required to pay a fee equal to 35 percent of Selkirk's increased monthly income from electricity that may be sold to third parties for the remainder of the 20-year term.

11.3.5 Thermal Energy Sales Agreement

The proposed sale of steam would be pursuant to an agreement, dated 15 February 1990, between Selkirk and G.E. The agreement continues for an initial term of 20 years from the commercial operation date and may be renewed for the longer of five years or the termination of the existing power sales agreement. Renewal provisions are applicable for up to 20 additional contract years. G.E. is required to purchase steam in excess of the minimum QF requirements. A base amount of the steam is priced at a 50 percent discount to G.E.'s

avoided steam costs, while all steam above the base amount is priced at full avoided cost. The steam discount may be reduced during any period Selkirk might suffer from economic hardship, with repayment when the hardship situation ceases. G.E. is required to pay for the minimum steam take, whether or not it is taken. Selkirk will purchase existing G.E. steam facilities to produce steam as needed and will utilize G.E.'s consumable waste to produce steam from the purchased facilities. G.E. has the first option to purchase the cogeneration facility if Selkirk decides to sell it.

11.3.6 Regulatory Status

Selkirk and Paramount jointly applied to the AERCB for a long-term energy removal permit on 11 August 1989. Selkirk stated that it expected to receive this permit in the spring of 1990. However, by the close of the proceedings there was no indication that it had been received.

No authorization is required for the removal of Paramount's reserves from the Northwest Territories.

The FERC granted QF status to the project on 28 September 1989. Additionally, DOE/FE import authorization was granted 15 November 1990.

11.4 Views of the Board

The Board is satisfied with the adequacy of Selkirk's supply relative to its requirements. The Board recognizes that Selkirk had Paramount's supply reviewed by a third party consultant with access to confidential reserves information that was unavailable to the Board. The Board's estimate of supply has been discounted due to the lack of supporting information for these estimates of reserves and may therefore be somewhat conservative.

The Board is satisfied that the downstream markets for the electricity and steam produced by the cogeneration facility are secure and that the facility would operate at a high load factor. That project financing, DOE/FE import authorization and FERC QF certification have been received has been noted by the Board. The Board also notes the expected commercial in-service date of January 1992.

The Board recognizes that transportation on all required pipelines has been arranged. Further, the Board is satisfied that all fixed costs of transportation in Canada will be recovered. In particular, the demand charge component of the price in the Selkirk/Paramount gas purchase contract ensures that demand charges on NOVA will be recovered. As Selkirk is the shipper on TransCanada, it will be directly responsible for the demand charges.

The commodity charge component of the export price is indexed to the natural gas and No. 6 fuel oil portion of Niagara Mohawk's fossil fuel index. The Board is thus of the view that the pricing provisions contained in the Selkirk/Paramount gas purchase contract permit adjustments in the export price to reflect changing market conditions. The Board also recognizes the flexibility that is in the agreement through the inclusion of renegotiation and arbitration conditions.

The Selkirk/Niagara Mohawk agreement ensures that Niagara Mohawk will make electricity purchases most days of the year, during which time the cogeneration facility will require natural gas as fuel. Paramount would contractually be the sole long-term supplier of such gas.

In the Board's view, the contract provision assuring Paramount's role as the sole supplier, coupled with the likely prospect that the cogeneration facility will operate at a high load factor, will ensure adequate take levels under the gas purchase contract.

The Board has reviewed the gas contract and has noted that it has been negotiated at arm's length.

In view of the fact that the gas proposed for export would come from reserves owned by Paramount, a demonstration of producer support was not required.

11.5 Decision

The Board has decided to issue a gas export licence to Selkirk.[1] In order for the licence to take effect, Governor in Council approval thereof is

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1. Although the gas export licence application was made by Selkirk, the licence will be issued to Selkirk Cogen Partners, L.P., as requested.

required. Appendix IV contains the terms and conditions of the licence, including a condition that the term of the licence shall commence on the later of 1 November 1991 or the date of first deliveries and shall end on 1 November 1993, unless exports have commenced under the licence on or before 1 November 1993, in which case the term would end 15 years and six months following the later of 1 November 1991 or the date of first deliveries.

Chapter 12

Kamine Carthage Cogeneration. Co., Inc. and Beta Carthage Inc.

12.1 Application Summary

By application dated 31 July 1989, Kamine Carthage, as general managing partner of Kamine/Besicorp Carthage L.P. applied to the Board under Part VI of the Act for a new export licence with the following terms and conditions:

Term	- Commencing 1 November 1991 and ending 31 October 2006 for a term of 15 years.	
Point of Export	- near Chippawa, Ontario	
Maximum Daily Quantity	- 402 10^3m^3	(14.2 MMcf)
Maximum Annual Quantity	- 140 10^6m^3	(4.9 Bcf)
Maximum Term Quantity	- 2 094 10^6m^3	(74.0 Bcf)
Tolerances	- 10 percent per day	

The gas reserves supporting the proposed export are located in Alberta, and would originate from existing pools and fields controlled by Renaissance Energy Ltd.("Renaissance").

The gas would be transported via the systems of NOVA within Alberta and TransCanada to the export point at Chippawa, Ontario. The gas would then be shipped on the Empire and Niagara Mohawk systems for delivery to Carthage, New York.

The gas proposed for export would be used to fuel a 49.9 MW gas-fired combined-cycle, cogeneration facility to be located at James River mill in Carthage, Jefferson County, New York. Niagara Mohawk would purchase the electricity and James River II, Inc. ("James River II") would purchase the steam.

12.2 Gas Supply

12.2.1 Supply Contracts

Kamine Carthage entered into a gas purchase contract with Renaissance for a term of 15 years commencing 1 November 1991. A schedule of lands dedicated to Kamine Carthage by Renaissance was appended to the application. Fifty percent of Renaissance's working interest in these dedicated lands is assigned to this contract and the execution of the Kamine Carthage export. The remaining 50 percent is assigned to an identical gas purchase contract with Kamine South Glens Falls for the execution of that export. The following gas supply discussion includes supply for both Kamine Carthage and Kamine South Glens Falls and for ease of reference in this Gas Supply section, the applicants will be referred to as "Kamine Beta".

12.2.2 Reserves

Renaissance, Kamine Beta's producer, adopted the AERCB's estimates of its established gas reserves. In addition, Renaissance included estimates of undiscovered potential from undrilled lands to support the application. Table 12-1 shows that the Board's estimate of established reserves is eight percent higher than Kamine Beta's estimate, while the Board's estimate of undiscovered potential from the undrilled lands is approximately 12 percent higher than Kamine Beta's estimate. The undiscovered potential represents 35 percent of the Board's total estimate of supply for Kamine Beta. The Board's estimate of established reserves is 8 percent higher than the applied-for volume.

The Board's evaluation of Kamine Beta's established reserves resulted in an estimate of 4 534 10^6m^3 (160 Bcf), which is eight percent higher than Kamine Beta's estimate of

Table 12-1

Comparison of Estimates of Kamine Beta's Established Gas Reserves and Undiscovered Potential With the Applied-for Volume

10^6m^3 (Bcf)

	Kamine Beta[1]	NEB[2]	Applied-for[3] Volume
Established Reserves:	4 182 (148)	4 534 (160)	4 186 (148)
Undiscovered Potential	2 202 (78)	2 464 (87)	______
TOTAL	**6 384 (226)**	**6 998 (247)**	**4 186 (148)**

1. As of 19 September 1990.
2. As of 31 December 1988.
3. Includes both Kamine Carthage and Kamine South Glens Falls.

established reserves. This is primarily due to the cumulative effect of small differences in several reservoir parameters.

The Board is unable to determine specific reasons for the differences in estimates of reserves for 19 pools, since Kamine Beta adopted the AERCB estimates of reserves for which the detailed supporting data are not yet available.

The Kamine Beta estimate of potential, 2 202 10^6m^3 (78 Bcf), is from undrilled lands held by Renaissance. The company stated that approximately 32 800 net hectares (128 sections) are available to support reserves additions. Renaissance also indicated immediate drilling activity was scheduled for up to seven undrilled sections.

The Board determined, through its analysis, that the undrilled lands could contain potential gas additions and directed its evaluation accordingly. The Board's analysis of the undrilled lands included discounting by an exploratory risk factor and resulted in a potential estimate slightly higher than that submitted by Renaissance of 2 464 10^6m^3 (87 Bcf). The undrilled lands are located in northcentral Alberta, some 100 kilometres north of Edmonton, and appear to have potential in the Cretaceous sands and Wabamun carbonates.

In its analysis of Kamine Beta's gas supply, the Board recognized approximately 126 pools, the majority of which are not producing. Most of the pools are relatively small and are located in central and eastcentral Alberta in Cretaceous zones. Ninety-five percent of the pools included in Kamine's submission have reserves estimated by the Board to be smaller than 100 10^6m^3 (3.5 Bcf) of initial marketable gas.

In summary, the Board's estimate of established reserves and undiscovered potential is higher than that of Kamine Beta and exceeds the applied-for volume by a substantial amount. The difference is related to the cumulative effect of small variances in reservoir parameters and to the methods used to determine potential from undrilled lands.

12.2.3 Productive Capacity

A comparison of the Board's and Kamine Beta's estimates of productive capacity with the combined applied-for requirements for the

Kamine Carthage and Kamine South Glens Falls projects is provided in Figure 12.1.

Kamine Beta provided an estimate of productive capacity from its dedicated reserves which demonstrated that it was capable of meeting the combined Carthage and South Glens Falls requirements throughout the term of the proposed export. Kamine stated that, should any shortfalls in productive capacity occur, Renaissance would bring on more supply from other uncontracted lands under its control.

The Board's estimate of productive capacity from Kamine Beta's dedicated reserves shows that Kamine Beta is capable of meeting its applied-for requirements until the year 2003.

While Kamine Beta has included extensive undiscovered potential in its application, the Board did not attempt to forecast productive capacity from those resources but recognizes that it is reasonable to expect some additional supplies could become available to Kamine Beta.

12.3 Market and Commercial Arrangements and Regulatory Status

12.3.1 Market

The 49.9 MW Carthage cogeneration plant, a QF facility that is expected to be in commercial operation in July 1991, will be located at the James River mill in Carthage, New York. The thermal host, James River II, will utilize the steam provided for the manufacture of paper towels and tissue paper. Niagara Mohawk, the power purchaser, provides electric service to residential, commercial and industrial customers in northern New York State including the cities of Albany, Buffalo, Syracuse and Watertown.

The cogeneration plant, a must-run facility, is designed to generate approximately 400,000 MW.h of energy annually. Financing for approximately $U.S. 70 million has been arranged from General Electric Capital Corporation.

Kamine Carthage testified that the facility's anticipated load factor was expected to be between 90 and 95 percent with down times being the result of routine maintenance and possible interruptions on the Niagara Mohawk system. The cogeneration plant is a must-run facility, meaning that Niagara Mohawk must purchase all electrical power generated from it. James River II has guaranteed the minimum purchase of steam to enable the facility to maintain its QF status.

12.3.2 Transportation

In Canada the gas would be transported to the Alberta/Saskatchewan border at Empress, Alberta on NOVA. TransCanada would transport the gas from that point to the international boundary near Chippawa, Ontario. In the U.S., the gas would be transported by the proposed Empire project from the international border to Empire's interconnection with the system of Niagara Mohawk near Syracuse, New York for delivery to the cogeneration facility at Carthage, New York.

Within Alberta the gas would be transported under long-term firm transportation agreements between Renaissance and NOVA.

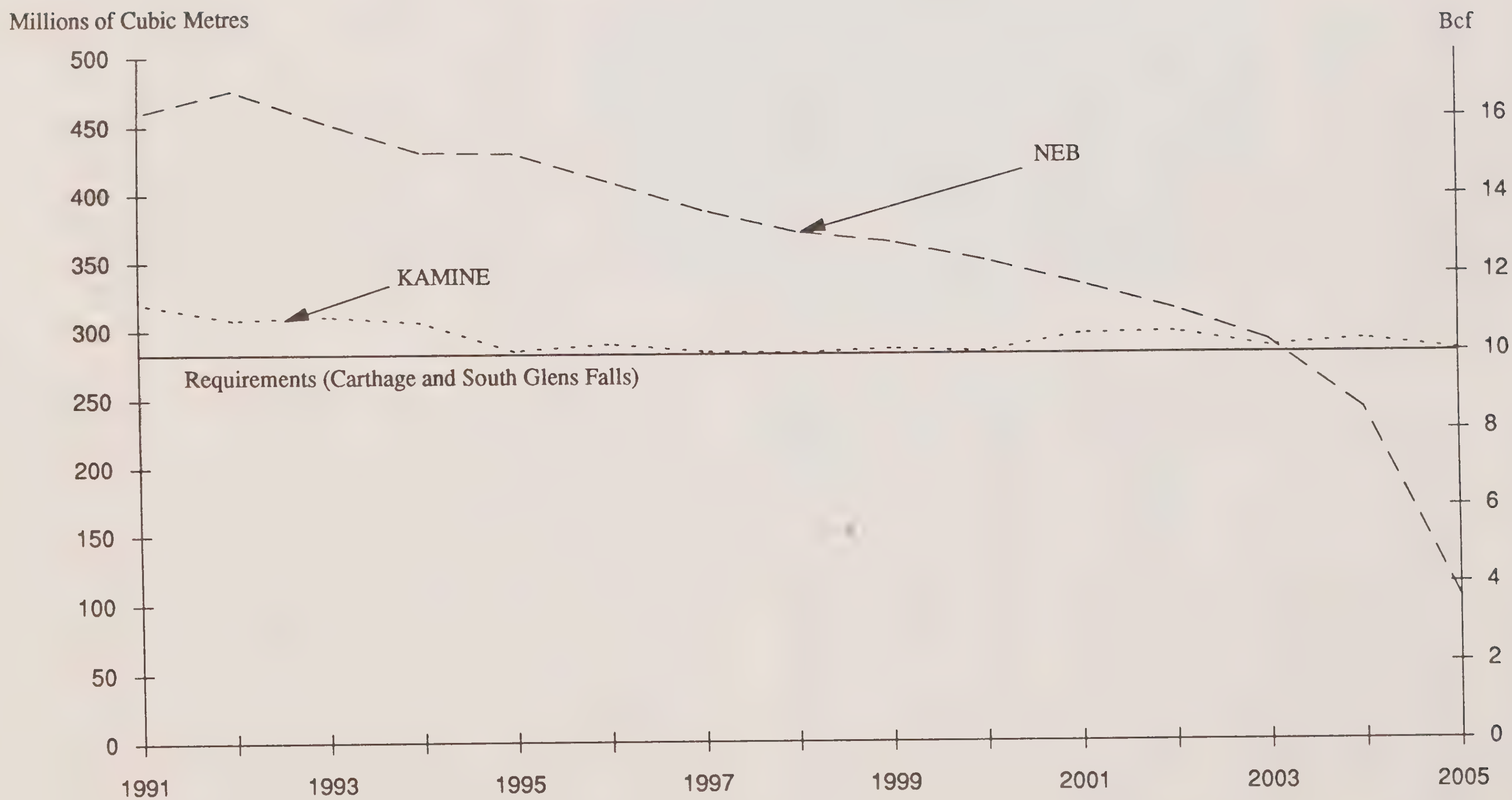
TransCanada and Kamine Carthage have entered into a precedent agreement dated 31 May 1989, as amended 12 January 1990 and 16 October 1990, for firm transportation of 402 10^3m^3 (14.2 MMcf) a day from Empress, Alberta to Chippawa, Ontario, beginning 1 November 1991 or as soon as possible thereafter. In addition to the incremental mainline facilities required on TransCanada to transport the Kamine Carthage volumes, there would also be a requirement for a new extension from Kirkwall to Chippawa, Ontario which is the subject matter of a separate TransCanada filing under section 58 of the Act referred to as the "Blackhorse Extension". That application is currently under review.

In the event that firm transportation service on TransCanada was not available until 1 November 1992, Kamine Carthage testified that it was confident that it could negotiate an assignment of space on TransCanada.

In the U.S., Kamine Carthage has entered into a precedent agreement with Empire dated 29 March 1989, as amended 29 December 1990 and 5 November 1990, for transportation from the international border to an interconnection with Niagara Mohawk on a firm basis beginning 1 November 1991. Finally, Kamine Carthage has

Figure 12.1

COMPARISON OF ESTIMATES OF ANNUAL PRODUCTIVE CAPACITY FOR KAMINE



executed an agreement in principle dated 20 January 1989 with Niagara Mohawk for transportation of the contracted volumes to Kamine's cogeneration facility. Niagara Mohawk would be required to construct new facilities in order to provide service to the proposed facility.

Kamine Carthage indicated that the transportation on Empire is uncertain at this stage. The necessary approval from the NYSPSC for the Empire project has been received. In the event that construction is delayed, Kamine Carthage would contract for interruptible service in the U.S. and Canada, taking delivery at Emerson, Manitoba from TransCanada with the gas being transported through the systems of Great Lakes Gas Transmission Company ("Great Lakes"), ANR Pipeline Company ("ANR"), Texas Gas Transmission Company ("Texas Gas"), and CNG.

12.3.3 Gas Sales Contract

A natural gas purchase agreement dated 9 May 1989, as amended 31 October 1989 and 30 October 1990, has been executed by Renaissance and Kamine Carthage and provides for the daily delivery of up to 402 10^3m^3 (14.2 MMcf) of gas at Chippawa, Ontario.

The gas contract is subject to several conditions precedent, including: receipt of all Canadian and U.S. regulatory approvals; finalization of all Canadian and U.S. transportation arrangements; buyer obtaining commitment for buyer's financing upon reasonable terms; and, buyer and seller executing an agreement governing the calculation of maximum price. These conditions precedent are to be met by 1 February 1991, otherwise, either party may terminate the gas contract.

The contract provides for Renaissance to be the sole supplier of the cogeneration plant's total gas requirements up to the level of the MDQ. Should Kamine Carthage purchase its gas from any other supplier, it would be obligated to pay Renaissance for those volumes not taken, as well as for all demand charges on the Canadian pipeline systems.

The base price, initially set at $ U.S. 1.37/GJ ($ U.S. 1.45/MMBtu) for the 1989 year, would be calculated at Empress, Alberta and would be adjusted quarterly to reflect increases or decreases in a market index composed of CNG's published natural gas rates for year-round service to Niagara Mohawk (weight of 50 percent), the average price of spot gas delivered into several pipelines in the U.S. (weight of 25 percent), and the price of No. 2 fuel oil at New York Harbour (weight of 25 percent). The resulting price is referred to as the adjusted price.

The base price is bound by a minimum and a maximum level. The minimum price is equal to the (contractual) base price, i.e. $ U.S. 1.37/GJ ($ U.S. 1.45/MMBtu) for 1989. The maximum price, which in 1989 was $ U.S. 2.28/GJ ($ U.S. 2.40/MMBtu), would be redetermined each year on the basis of a formula which takes into account, in equal measure, changes in Niagara Mohawk's average price for electricity under the power purchase agreement and the U.S. consumer price index.

Based on the foregoing contractual provisions, the estimated price at the Alberta border under this contract as of January 1990 was $Cdn. 1.95/GJ ($Cdn. 2.09/MMBtu).

The base price and the composition of the market index can be renegotiated to reflect market prices during the month of April 1991 and in the month of April prior to the fifth, tenth and fifteenth years of the contract. If, by the following October, the parties are unable to agree on a renegotiated base price or market index, the agreement may be terminated on one year's written notice. The renegotiated base price may not vary by more than 25 percent from the current adjusted price within the bounds set by the minimum and maximum price.

If the adjusted price were less than the minimum price, Renaissance would receive the minimum price. If the adjusted price were to exceed the maximum, Renaissance would be paid the maximum price and the difference between the revenue generated by the maximum price and the adjusted price would be credited to a deferral account. The account would earn interest at the prime rate. Once the adjusted price was again between the minimum and maximum prices, Renaissance would be paid the maximum price by drawing funds from the deferral account. Renaissance would have a security interest in the project represented by the deferral account. Any

balance left in the deferral account at the end of the contract term, or upon termination of the agreement, would be paid to the producer.

Kamine Carthage testified that, as a result of its contractual commitment to buy gas only from Renaissance and to pay the demand charges on TransCanada, gas would be taken at a consistently high load factor.

12.3.4 Power Sales Agreement

The proposed sale of electricity from the Carthage cogeneration plant will be pursuant to an agreement, dated 5 June 1987, between Kamine Carthage and Niagara Mohawk. The agreement was assigned to Kamine/Besicorp Carthage L.P. on 31 October 1989. The power agreement will continue for a term of 20 years from the date of initial operation.

The Carthage plant is a must-run facility, with Niagara Mohawk accepting all the electricity produced by the plant. The price Niagara Mohawk will pay will be the greater of \$ 0.06/kW.h or the rate applicable to qualifying on-site generation suppliers, as that rate may be changed, amended or supplemented by the NYSPSC. If the NYSPSC rate is not utilized, then the rates will be calculated as set out in the agreement. The agreement includes rates for peak and off-peak pricing which are calculated for projected avoided production, capacity and transmission costs as approved by the NYSPSC. Carthage has relinquished entitlement to any upward adjustment in statutory minimum rates. The electricity sold from the Carthage plant does not require wheeling by third parties.

12.3.5 Thermal Energy Sales Agreement

The proposed sale of thermal energy from the Carthage plant will be pursuant to the energy services agreement, dated 31 October 1989, between Kamine/Besicorp Carthage L.P. and James River II. The agreement will remain in effect for 20 years from the date of initial operation. James River II will utilize a sufficient amount of steam from the plant to ensure the maintenance of the plant's QF status.

A redacted version of the energy services agreement was filed with the application because the Applicant considered the balance of the thermal sales agreement commercially sensitive and confidential. The James River Corporation, the parent company of James River II, in a guarantee, dated 31 October 1989, has unconditionally guaranteed the minimum purchase and use of steam to ensure the cogeneration plant's QF status. In the event the mill were to be sold, James River Corporation has the right to transfer its guarantee obligations.

12.3.6 Regulatory Status

Renaissance applied to the AERCB for a long-term gas removal permit on 14 June 1989. The AERCB has recommended that Renaissance be permitted to remove 4 000 $10^6 m^3$ (141.2 Bcf) of gas from the province over a 15-year term. Renaissance indicated during the hearing that the permit was awaiting Lieutenant Governor in Council approval and was expected to be granted in the near future. The requested volumes include both the Kamine Carthage and Kamine South Glens Falls volumes. Subsequent to the close of the hearing, Kamine Carthage, by letter dated 18 March 1991, informed the Board that Renaissance had received Removal Permit No. GR 90-159 from the AERCB. The removal permit allows Renaissance to remove 3 975 $10^6 m^3$ (140 Bcf) of natural gas from Alberta over a 15-year term.

Kamine/Besicorp Carthage L.P. applied for DOE/FE import authorization on 21 July 1989, and approval was granted on 28 March 1990. Kamine Carthage indicated that the DOE/FE import authorization has been obtained for the Emerson, Manitoba import point, and not Chippawa, Ontario. This import point would be changed to Chippawa, Ontario when the Empire pipeline project goes into service.

The cogeneration plant has been granted QF status by the FERC.

12.4 Views of Intervenors

CNG submitted that if a licence were to be issued, it should be conditioned to require Kamine Carthage to supply satisfactory evidence of specific authority to import Canadian gas at

Chippawa. Kamine Carthage opposed CNG's submission observing that changing the import point to Chippawa was simply a matter of notifying the DOE/FE. In addition, Kamine Carthage held the view that such a condition would not serve a useful purpose, given that a sunset clause, to which Kamine Carthage did not object, would be included in any licence issued.

CNG also expressed the view that there was considerable uncertainty with respect to transportation arrangements and stated that if a licence was to be issued to Kamine Carthage, it should not commence earlier than 1 November 1992 and should be conditioned to require Kamine Carthage to provide satisfactory evidence of firm transportation arrangements to and from the Chippawa export point and should terminate if deliveries at Chippawa have not commenced before 31 October 1993. As previously noted, Kamine Carthage was of the view that inclusion of a sunset clause precluded the need for the type of conditions advocated by CNG. In addition, Kamine Carthage noted that facilities would not be constructed if downstream transportation arrangements had not been completed.

12.5 Views of the Board

The Board is of the view that sufficient undiscovered potential would become available to Kamine Beta from its undrilled lands to alleviate any shortfalls in productive capacity to meet the combined Kamine Carthage and Kamine South Glens Falls project requirements. The Board is therefore satisfied as to the adequacy of supply relative to requirements.

The Board is satisfied that the downstream markets for the electricity and steam produced by the Kamine Carthage facility are secure and that the facility would operate at a high load factor.

The Board notes that final project financing, QF certification, DOE/FE import authorization at Emerson, Manitoba and other necessary approvals and authorizations have been secured. In this regard, the Board notes that when the Applicant finds it necessary to change the export point from Emerson, Manitoba to Chippawa, Ontario, it can do so by a notification to the DOE/FE and no other amendment or approval would be required. The Board also notes the cogeneration facility's expected completion date of July 1991.

The Board notes that transportation has been arranged on all required pipelines. Further, the Board is satisfied that Kamine Carthage would recover all fixed costs of transportation in Canada. The gas sales contract would ensure that demand charges on NOVA and TransCanada are recovered, independent of the price of gas. In this regard, the Board notes that Kamine Carthage has provided a letter of credit from its bankers for a term of two years in an amount equal to one year of TransCanada's firm service demand charges based on Kamine Carthage's contracted demand times the NEB-approved firm service demand toll.

The Board considers that the transportation situation downstream, with respect to Empire State, is uncertain at this stage. The NYSPSC has approved the Empire State project. However, the Board has yet to deal with the Blackhorse extension, and Empire State is contingent upon this approval. The Board notes, however, that Kamine Carthage, through Energy Market Exchange, would use any available interruptible transport space to bring Renaissance gas to Emerson, Manitoba, down Great Lakes to ANR, across Lebanon, Ohio to CNG, and then, via Niagara Mohawk, to the facility.

The Board notes that the contract price under the gas sales contract has been negotiated at arm's length according to an agreed-upon formula which includes a market fuel index based on competitive fuels in the market place. The quarterly index adjustment and the opportunity to adjust the base price should reflect, over the contract term, fair market prices of gas sold in the market where the Kamine Carthage facility is located. In addition, the Board notes that price opener clauses, after an interval of five years, would provide flexibility to the contract and the Board is satisfied that the provisions of the pricing mechanism would ensure that the contract price would respond to changing market conditions over the term of the contract.

The Board has reviewed the gas contracts and has noted that they have been negotiated at arm's length, and that the pricing terms are such that the arrangement is likely to be durable over the contract/licence term. The Board notes that the

Canadian producer has endorsed the proposed export by virtue of its having executed the gas sales contract.

12.6 Decision

The Board has decided to issue a gas export licence to Kamine Carthage, subject to the approval of the Governor in Council. Appendix IV contains the terms and conditions of the licence, including a condition that the term of the licence shall commence on 1 November 1991 and shall end on 1 November 1993, unless exports have commenced under the licence on or before 1 November 1993, in which case the term would end on 31 October 2006.

Chapter 13

Kamine South Glens Falls Cogeneration Co., Inc. And Beta South Glens Falls Inc.

13.1 Application Summary

By application dated 31 July 1989, Kamine South Glens Falls, as general managing partner of Kamine/Besicorp South Glens Falls L.P., applied to the Board under Part VI of the Act for an export licence with the same terms and conditions as the Kamine Carthage application dealt with in Chapter 12, but with the exception of the point of export which in this case would be Emerson, Manitoba. Specific details are provided in section 12.1.

The gas reserves supporting the proposed export are located in Alberta, and would originate from existing pools and fields controlled by Renaissance.

The gas would be transported via the systems of NOVA within Alberta and of TransCanada to the export point at Emerson, Manitoba. The gas would then be shipped on the Great Lakes, ANR, CNG and Niagara Mohawk systems for delivery to South Glens Falls, New York.

The electricity and steam would be purchased by the same parties as in the Kamine Carthage application.

13.2 Gas Supply

The Kamine South Glens Falls application shares a common supply with Kamine Carthage. The pertinent supply information is detailed in section 12.2.

13.3 Market and Commercial Arrangements and Regulatory Status

13.3.1 Market

Kamine South Glens Falls has received financing for approximately $ U.S. 65 million from General Electric Capital Corporation.

Although the cogeneration facility is in a different location, output from the South Glens Falls, New York facility would be sold to the same parties and used in a manner identical to the Kamine Carthage application. Please refer to section 12.3.1 for market details.

13.3.2 Transportation

Volumes of gas associated with the applied-for export licence would be transported in Alberta under firm, long-term transportation agreements between Renaissance and NOVA. NOVA would deliver the gas to the interconnection of its system with TransCanada at Empress, Alberta, at which delivery point Kamine South Glens Falls would take ownership of the gas.

TransCanada would transport the gas from Empress, in Alberta to Emerson, Manitoba where TransCanada's facilities interconnect with Great Lakes. TransCanada and Kamine/Besicorp South Glens Falls L.P. have entered into a precedent agreement dated 31 May 1989, as amended 12 January 1990 and 16 October 1990, for firm transportation of 402 10^3m^3 (14.2 MMcf) a day from Empress, Alberta to Emerson, Manitoba, beginning 1 November 1991, or as soon thereafter as possible.

A precedent agreement has been executed with Great Lakes to obtain firm transportation subject to the necessary facility expansions being

completed by 1 April 1991. In this regard an application has been made to FERC for the requisite facilities. If the facility expansions are not completed by that date, the Applicant intends to transport the gas on an interruptible basis, using existing pipeline capacity, until such time as the necessary facilities have been completed.

Kamine South Glens Falls would be responsible for all transportation charges and costs associated with the delivery of gas in Canada and in the U.S. from the delivery point at Empress, Alberta to the facility in South Glens Falls, New York.

A precedent agreement dated 15 December 1988, as amended 24 August 1990, has been executed between ANR and Kamine/Besicorp South Glens Falls L.P.

A precedent agreement dated 27 February 1989, as amended 5 October 1990, has also been executed between Kamine/Besicorp South Glens Falls L.P. and CNG for firm transportation.

Approvals for construction of facilities and service authorizations by FERC are still pending for the Great Lakes, ANR and CNG systems.

Kamine/Besicorp South Glens Falls L.P. executed a precedent agreement dated 17 January 1989 with Niagara Mohawk to transport the gas to the cogeneration facility.

13.3.3 Gas Sales Contract

A natural gas purchase agreement dated 9 May 1989, as amended 31 October 1989 and 30 October 1990, has been executed by Renaissance and Kamine South Glens Falls. The gas contract is for a term of 15 years from 1 November 1991. The terms and conditions of this agreement are the same as those in the Kamine Carthage/Renaissance agreement, the details of which are described in section 12.3.3.

13.3.4 Power Sales Agreement

The 5 June 1987 power sales agreement between Kamine South Glens Falls and Niagara Mohawk is the same as the agreement Niagara Mohawk entered into with Kamine Carthage. Details of the South Glens Falls power sales agreement are as described in section 12.3.4.

13.3.5 Thermal Energy Sales Agreement

The 31 October 1989 energy services agreement between Kamine/Besicorp South Glens Falls L.P. and James River II, is the same as the agreement James River II entered into with Kamine/Besicorp Carthage L.P. Details of the South Glens Falls energy services agreement are described in section 12.3.5.

13.3.6 Regulatory Status

Kamine South Glens Falls applied for DOE/FE import authorization on 21 July 1989 and approval was received on 5 February 1990. Details with regard the Alberta removal permit are as described in section 12.3.6. The cogeneration plant has received QF status from the FERC.

13.4 Views of the Board

The Board is satisfied that the markets for the electricity and steam produced by the Kamine South Glens Falls facility are secure and that the facility would operate at a high load factor.

The Board notes that final project financing, QF certification, DOE/FE import authorization at Emerson, Manitoba and other necessary approvals and authorizations have been secured. In this regard the Board notes that FERC approvals and authorization for service are still pending for Great Lakes, ANR and CNG system. The Board is of the view that the sponsor of this export project would obtain the necessary approvals and authorizations in time for the gas to flow to the cogeneration facility. The Board also notes the cogeneration facility's expected completion date of July 1991.

The Board notes that transportation has been arranged on all required pipelines and is satisfied that all associated fixed costs of transportation in Canada would be recovered. The gas sales contract would ensure that demand charges on NOVA and TransCanada are recovered, independent of the price of gas. In this regard, the Board notes that Kamine South Glens Falls has provided a letter of credit from its bankers for a term of two years and in an amount equal to one year of TransCanada's firm service demand

charges based on Kamine South Glens Falls contracted demand times the NEB-approved firm service demand toll.

The Board notes that the contract's pricing formula includes a market fuel index based on competitive fuels in the market place. The quarterly index adjustment and the opportunity to adjust the base price should reflect, over the contract term, fair market prices of gas sold in the market where the Kamine South Glens Falls facility is located. In addition, the Board notes that price opener clauses after an interval of five years would provide flexibility to the contract. The Board is satisfied that the provisions of the pricing mechanism would ensure that the contract price would respond to changing market conditions over the term of the contract.

The Board notes that Kamine South Glens Falls, through Energy Market Exchange, would use any available interruptible transport space to bring Renaissance gas to Emerson, Manitoba, down Great Lakes to ANR, across Lebanon, Ohio to CNG, and via Niagara Mohawk to the facility in the event there are delays in the expansion of U.S. downstream transportation facilities.

The Board has reviewed the gas contracts and has noted that they have been negotiated at arm's length, and that the pricing terms are such that the arrangement is likely to be durable over the contract/licence term.

The Board notes that the Canadian producer has endorsed the proposed export by virtue of its having executed the gas contract.

13.5 Decision

The Board has decided to issue a gas export licence to Kamine South Glens Falls, subject to the approval of the Governor in Council. Appendix IV contains the terms and conditions of the licence, including a condition that the term of the licence shall commence on 1 November 1991 and shall end on 1 November 1993, unless exports have commenced under the licence on or before 1 November 1993, in which case the term would end on 31 October 2006.

Chapter 14

New England Power Company

14.1 Application Summary

By application dated 4 August 1989, as amended, NEP applied to the Board under Part VI of the Act for a natural gas export licence with the following terms and conditions:

Term	- commencing 1 November 1991 at the earliest or 1 November of the year in which such exports commenced for a period of 15 years.
Point of Export	- near Iroquois, Ontario
Maximum Daily Quantity	- 1 700 10^3m^3 (60.0 MMcf)
Maximum Annual Quantity	- 621 10^6m^3 (21.9 Bcf)
Maximum Term Quantity	- 9 308 10^6m^3 (328.5 Bcf)
Tolerances	- 10 percent per day and 2 percent per year

The gas proposed for export would be produced in Alberta and British Columbia from established reserves and undiscovered potential on lands controlled by BP Resources Canada Limited ("BP Resources"), Renaissance, Sceptre, and Triton Canada Resources Limited ("Triton"). The British Columbia reserves are located adjacent to the Alberta border and would be connected to the NOVA system.

NOVA would transport the gas to Empress, Alberta and TransCanada would transport the gas to the export point near Iroquois, Ontario. The gas would then be shipped on the IGTS, Tennessee and Algonquin systems for delivery to NEP's facilities in Massachusetts and Rhode Island.

14.2 Gas Supply

14.2.1 Supply Contracts

NEP executed 20-year gas supply contracts with BP Resources, Sceptre, Triton, and a 15-year contract, with an option for an additional five years, with Renaissance.

Under the terms of its supply contract, Renaissance has dedicated specific lands in Alberta to NEP. Renaissance has also agreed to develop additional potential reserves in the Graindale area of Alberta. BP Resources, Sceptre and Triton have submitted gas supply estimates for pools in Alberta and British Columbia but have not dedicated those lands specifically to NEP.

These contract arrangements are discussed further in section 14.3.3 of these Reasons.

14.2.2 Reserves

Table 14-1 shows that the Board's estimate of NEP's established gas reserves is five percent lower than NEP's estimate (including Sceptre), but exceeds the applied-for volume by 42 percent. In addition to the established reserves, NEP included as part of the total project supply an estimate of undiscovered potential for undrilled lands. The Board's estimate of undiscovered potential is 63 percent lower than NEP's estimate and represents nine percent of the Board's total estimate. With the inclusion of undiscovered potential, the Board's total estimate is 17 percent lower than NEP's estimate, but exceeds the applied-for volume by 57 percent.

The Board's estimate of potential attributed to the undrilled lands reflects discounting by an appropriate risk factor to reflect the uncertainty inherent in these estimates. The Board has also assessed the established reserves to be provided by Sceptre under corporate warranty. For

Table 14-1

Comparison of Estimates of NEP's Established Gas Reserves and Undiscovered Potential With the Applied-for Volume

10^6m^3 (Bcf)

	NEP[1]	**NEB**[2]	**Applied-for Volume**
Established Reserves	10 847 (383)	10 091 (356)	6 206 (219)
Undiscovered Potential	3 680 (130)	1 378 (49)	
Total (excluding Sceptre)	**14 527 (513)**	**11 469 (405)**	
Sceptre Est. Reserves[3]	3 102 (110)	3 102 (110)	3 102 (110)
Total (including Sceptre)	**17 629 (623)**	**14 571 (515)**	**9 308 (329)**

1. As of 1 January 1990.
2. As of 31 December 1988.
3. Sceptre's corporate supply has been submitted in support of both the NEP and Enserch applications; for presentation purposes that portion of the corporate supply necessary to meet the requirements for the NEP application has been included above.

purposes of review and presentation of the NEP application, the Board has allocated to this application a portion of the Sceptre corporate supply pool equivalent to Sceptre's requirements of 3 102 10^6m^3 (109.5 Bcf). A more comprehensive description of the Board's assessment of Sceptre's corporate supply is provided in section 5.2 of these Reasons.

The divergence between NEP's and the Board's estimates of established reserves can be attributed largely to the cumulative effect of differences in several reservoir parameters for various pools in the application, including area assignments for single-well pools and interpretations of net pay. The majority of the difference in the total estimates by the Board and NEP can be attributed to the assessment of undiscovered potential. The Board's estimate of undiscovered potential for undrilled lands was considerably lower than that estimated by NEP, largely due to differences in the approach to risk discounting these estimates.

The Board's estimate of these reserves indicates that the aggregate supply available from NEP's producers is adequate to meet the applied-for volume. Discrepancies in the estimates of reserves by the Board and NEP for each of the four producers are outlined below.

The Board's estimate of NEP's established reserves provided by Renaissance was similar to Renaissance's estimate. Renaissance based its estimates of reserves on AERCB data.

The Renaissance estimates of potential were for the Graindale area of Alberta, on lands referred to as undrilled. Renaissance submitted estimates of potential, discounted by a risk factor, for 24 sections of land. Renaissance assigned a risk factor of either 50 percent or 60 percent in estimating potential to lands adjacent to proven

reserves. Also, Renaissance used full-section area assignments and assumed that a minimum of two and a maximum of four pay zones would be present in each section.

The Board's assessment of potential for the undrilled lands is 63 percent less than the estimate submitted by NEP/Renaissance. The estimates differ due to variations in the methodology used to determine the appropriate risk factor and to differences in the reserves per section assignment (which was a result of differences in drainage area, net pay assignments and the number of pay zones assumed in each section).

The Board analyzed each zone independently. The Board estimated potential by assigning reserves based on average reserves per section from adjacent established pools. Then a success rate based on exploratory drilling results in the immediate area of the undrilled lands was calculated. The estimate based on the reserves per section assignment was discounted by the risk factor. The Board's risk discounting was substantially higher than that of Renaissance. The Board noted that all of the established pools in the area are single-well pools and that only three wells have more than one pay zone, with the maximum being two pay zones.

The Board's estimate of reserves for Triton was somewhat lower than Triton's estimate, primarily due to differences in interpretation of pool parameters in the Winefred Lake area.

Triton stated that it largely used 256 hectare area assignments, based on performance of existing wells. It submitted that the majority of its pools are composed of Colony and McMurray wells in Cold Lake, Hardy/Winefred and Thornbury areas, where the cumulative produced volumes to date for individual wells are often greater than the reserves estimated using 256 hectare area assignments. Triton provided several examples to illustrate the basis for its estimates of reserves. The Board, in its review of Triton's wells, found that the majority of the wells had already been mapped by the Board as multi-well pools rather than single-well pools and was satisfied that the reserves assignments used by Triton were appropriate.

The Board's estimate of reserves for BP Resources was slightly lower than BP Resources' estimate, primarily due to the cumulative effect of small differences in pool parameters. BP Resources stated that area assignments for single-well pools is essentially the same as those of the Board and the AERCB and that geological and geophysical evidence as well as performance data is used in determining the appropriate area assignments. The Board reviewed these estimates and is generally in agreement with the area assignments used by BP Resources.

The Board's estimate of NEP's reserves provided by Sceptre (corporate warranty supply) was similar to Sceptre's estimate (refer to section 5.2.2.1). The Board notes, however, that this corporate supply must satisfy not only the NEP requirements but other requirements as well, including the Encogen application in this proceeding.

In its analysis of NEP's gas supply, the Board recognized 337 pools (excluding Sceptre's corporate supply pools), the majority of which are not producing. Most of the pools are relatively small and are located in the eastern portion of the province in Cretaceous zones. Seventy-three percent of the pools for which NEP submitted reserves have reserves estimated by the Board to be less than $100\ 10^6m^3$ (3.5 Bcf) of initial marketable gas.

In summary, the Board's estimate of reserves is somewhat less than the NEP estimate, but exceeds the applied-for volume by a considerable amount. The divergence in the estimates is due primarily to differences in net pay assignments, differences in the risk assessment inherent in the assignment of potential to undrilled lands and the cumulative effect of minor variances in other reservoir parameters.

14.2.3 Productive Capacity

Supply for NEP's export is provided by four producers, Triton, Renaissance, BP Resources and Sceptre. Sceptre refers to its gas purchase contract with NEP as a corporate warranty sale, which Sceptre intends to supply from its pool of undedicated reserves in Alberta.

For illustrative purposes, the Board analyzed NEP's productive capacity in two stages. In the first stage productive capacity available from Triton, Renaissance and BP Resources was estimated relative to that portion of NEP's requirements to be provided by these producers. In the second stage Sceptre's corporate warranty supply was reviewed in the context of its total requirements, including those of NEP, to be provided by this source of supply.

A comparison of the Board's and NEP's estimates of productive capacity for Triton, Renaissance and BP Resources with the corresponding portion of the applied-for requirements is shown in Figure 14.1. NEP's estimate of productive capacity indicates that requirements can be met until 1999, with increasing shortfalls anticipated thereafter. The Board's projection of productive capacity shows that it is likely that NEP will be capable of meeting the applied-for requirements throughout the term of the proposed export licence. The Board's projection of productive capacity was adjusted to account for unused productive capacity relative to requirements.

The Board's analysis of productive capacity from the reserves included in Sceptre's corporate warranty supply relative to its total requirements including NEP, to be provided by this supply source is detailed in section 5.2.3 of these Reasons.

NEP included some undiscovered potential in its application. The Board did not attempt to estimate productive capacity from this potential but recognizes that it is reasonable to expect that some additional supplies could become available in the future.

14.3 Market and Commercial Arrangements and Regulatory Status

14.3.1 Market

The gas proposed for export would be used by NEP and its affiliates to generate electricity and, in particular, would displace residual fuel oil currently being burned at NEP's 430 MW Brayton Point Station Unit 4 located in Somerset, Massachusetts, and would fuel a 450 MW combined-cycle repowering of three electric power generation units at the Manchester Street Station in Providence, Rhode Island. The gas may also be used to fuel the South Street Station, also located in Providence, Rhode Island.

NEP is engaged in the generation and transmission of electric power for sale to affiliated and unaffiliated utilities in the New England region. It is also the wholesale generation subsidiary of New England Electric System ("NEES"). NEES' subsidiaries include three retail operating companies which, combined, provide electricity to over 1.2 million customers in Massachusetts, Rhode Island, and New Hampshire.

The Brayton Point Station is scheduled for start-up in November 1991, and will require approximately 2 690 $10^3m^3/d$ (95 MMcfd) of gas. The Manchester Street Station, expected to be in service during the 1994/95 contact year, will require approximately 2 180 $10^3m^3/d$ (77 MMcfd).

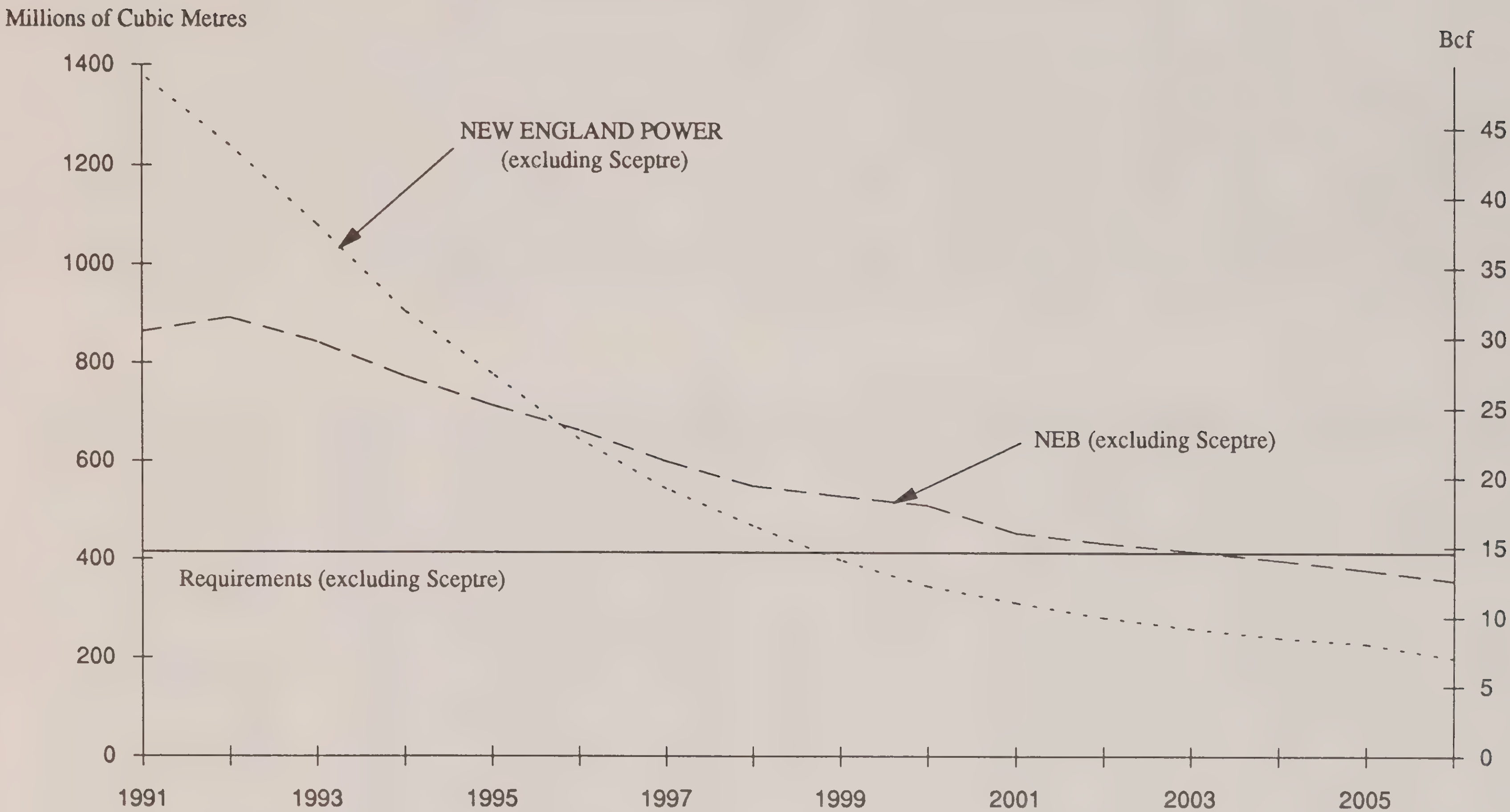
NEP has undertaken this proposed export in order to comply with Massachusetts' environmental legislation to improve air quality by displacing oil at the Brayton Point Station; to add generation capacity to meet growing electricity demand in New England through the natural gas repowering of the Manchester Street Station; to diversify its fuel supply portfolio by adding gas to its electric generation fuel mix; and, to diversify its gas supply portfolio by adding Canadian sources.

NEES has projected that, in the absence of significant conservation by its customers, annual peak load growth will average around 2.9 percent over the next 15 years. Successful conservation and load management programs could limit annual peak load growth to 1.8 percent. In 1988, new summer and winter peak loads of 4,107 MW and 4,019 MW respectively occurred. In addition to the facilities which would receive gas as a result of the applied-for licence, NEES anticipates that additional generation capacity may be required by the late 1990's.

In reference to the NEES and its three retail subsidiaries, the division of requirements by customer class is 34 percent residential, 32 percent commercial, 22 percent industrial and 12 percent other. The commercial class has demonstrated the strongest growth over the past

Figure 14.1

COMPARISON OF ESTIMATES OF ANNUAL PRODUCTIVE CAPACITY FOR NEW ENGLAND POWER [1]



1. Estimates of productive capacity from Triton, BP Resources and Renaissance compared to that portion of NEP's requirements to be provided by these producers. The remainder of the requirements are to be provided from Sceptre's corporate supply, which is outlined in Section 6.3 of these Reasons.

five years, at five percent annually, and is expected to show the greatest growth in the future.

The applied-for gas would comprise roughly one-third of the volumes in NEP's corporate strategy of obtaining up to 5 380 $10^3m^3/d$ (190 MMcfd) for use at the five power stations. Of the remaining 3 680 $10^3m^3/d$ (130 MMcfd), which NEP plans to contract with U.S. suppliers, 1 700 $10^3m^3/d$ (60 MMcfd) would be under long-term contract.

NEES' energy mix in 1988 consisted of 44 percent coal, 27 percent oil, 17 percent nuclear, 11 percent hydro and alternates, and one percent gas. It is anticipated that the addition of firm gas would add security and reliability. By 1999, it is projected that NEES' energy mix would consist of 37 percent coal, ten percent oil, 15 percent nuclear, ten percent hydro and alternates, and 28 percent gas.

NEP anticipates takes at a 100 percent load factor from the four Canadian suppliers during the licence term.

14.3.2 Transportation

Gas from Alberta and from the Mica field on the British Columbia/Alberta border would be shipped to Empress, Alberta on the NOVA system. TransCanada would transport the gas from Empress to IGTS' system for delivery to Tennessee's system near Wright, New York. Tennessee would transport the gas to its interconnection with Algonquin near Mendon, Massachusetts. Algonquin would then deliver the gas to NEP's plants located near Somerset, Massachusetts and Providence, Rhode Island.

Each of the four Canadian producers has renewable arrangements in place for sufficient firm capacity on NOVA to fulfill their obligations to NEP.

NEP and TransCanada executed a precedent agreement dated 10 May 1989, as amended, for 1 700 $10^3m^3/d$ (60 MMcfd) of firm service. The contract term commences no earlier than 1 November 1991 and expires 31 October 2006.

On 11 October 1989, NEP entered into precedent agreements with both IGTS and Tennessee for firm transportation service. NEP and Algonquin also executed a precedent agreement dated 13 January 1989, as amended, for firm service. The required facilities additions on IGTS were approved by FERC on 14 November 1990.

The laterals from Algonquin to NEP's facilities would be built, owned, and operated by Algonquin. Approval by FERC of the Tennessee and Algonquin facilities is still pending.

14.3.3 Gas Sales Contracts

NEP has entered into a natural gas purchase agreement with each of BP Resources, Renaissance, Sceptre, and Triton for delivery of gas at Empress, Alberta. Early delivery of gas on a reasonable efforts basis prior to licence start-up is provided for by each of the producers with the exception of Renaissance.

Each contract is subject to several conditions precedent, including receipt of all necessary Canadian and U.S. regulatory approvals and the finalization of all Canadian and U.S. transportation arrangements. The conditions precedent in the agreements with BP Resources and Renaissance are to be satisfied by various specified dates. Those in the agreements with Sceptre and Triton are to be satisfied by 1 November 1993.

The pricing structure in each of the contracts, except Renaissance's, is comprised of demand and commodity charge components. The demand charge consists of the producers' NOVA transportation charges attributable to the sale. Since NEP is the shipper on TransCanada, it would pay the relevant TransCanada fixed cost of transportation. The Renaissance contract contains only a commodity charge component.

In each of the four contracts, should price redetermination not be agreed upon within three months of the initial request for it, then either party may terminate the contract.

Other contractual provisions unique to each of the contracts are discussed below.

14.3.3.1 BP Resources Canada Limited

NEP and BP Resources executed a gas sales contract dated 17 January 1989. The contract is for a 20-year term and provides for the daily delivery of up to 283 10^3m^3 (10 MMcf). The contract also contains a provision for NEP to request a 283 10^3m^3 (10 MMcf) increase in the MDQ.

Should NEP's takes average less than 80 percent of the MDQ in a contract year, then NEP may elect to pay a specified reservation fee. Whether NEP elects to make such a payment or not, BP Resources may opt to reduce the MDQ for the remainder of the contract's term. Off-system sales by either party are permitted.

The commodity charge component of the price is adjusted monthly from an initial level of \$ U.S. 1.26/GJ (\$ U.S. 1.33/MMBtu). Adjustments to the commodity charge would be comprised equally of changes in specified mid-Continent and Gulf Coast gas prices and of changes in the average delivered oil cost to NEP's electric generation facilities.

The estimated price at the British Columbia/Alberta border as of January 1990 under this contract was \$ Cdn. 2.44/GJ (\$ Cdn. 2.62/MMBtu).

Redetermination of the contract price is permitted every second year under specified circumstances for each party. BP Resources may request redetermination of the price if, over any four consecutive months during the preceding two years, it averaged less than 90 percent of the average Alberta price during the same period. NEP may request redetermination of the contract price should such a price not allow NEP's generation units to be dispatched at an average 90 percent net capability during any consecutive four-month period over the preceding two years.

14.3.3.2 Renaissance Energy Ltd.

NEP executed a gas sales contract dated 17 January 1989 with Renaissance for a 15-year term with a possible five-year extension. The contract provides for the daily delivery of up to 425 10^3m^3 (15 MMcf). NEP may request that the MDQ be increased by up to 708 10^3m^3 (25 MMcf).

If NEP's takes average less than the MAQ for any contract year, then Renaissance may elect to reduce the MDQ. Should takes fall short of the MAQ for two consecutive years, then Renaissance may terminate the contract. Either party may, however, make off-system sales.

The commodity charge component of the price is adjusted monthly from an initial level of \$ U.S. 1.30/GJ (\$ U.S. 1.37/MMBtu). Adjustments to the commodity charge would be comprised equally of the changes in a basket of four fossil fuel prices. These fuel prices are Tennessee's and Tetco's current average cost of purchased gas and NEP's average delivered fuel oil and coal costs. Renaissance is not directly reimbursed for its transportation charges on NOVA. Instead, it is compensated through a higher contractual base price. Redetermination of the contract price is permitted after the second contract year and every two years following the last redetermination.

The estimated price at the Alberta border as of January 1990 under this contract was \$ Cdn. 2.04/GJ (\$ Cdn. 2.19/MMBtu).

14.3.3.3 Sceptre Resources Limited

NEP and Sceptre executed a gas sales contract dated 31 August 1988 with a 20-year term and daily deliveries of up to 567 10^3m^3 (20 MMcf).

Should NEP's average takes over a contract year be less than 65 percent of the MDQ, then NEP may elect to pay a specified reservation fee. Should NEP elect not to make such a payment, Sceptre may opt to reduce the MDQ for the remainder of the contract term.

The gas contract's pricing structure provides for a contribution to royalty payments, should such payments be based on a price in excess of the price in the contract.

The commodity charge component is calculated monthly and is equal to one-half the AAMP, as published by the Government of Alberta, plus one-half the difference between NEP's weighted average variable fossil fuel cost and all variable transportation commodity costs applicable to the export. Also included in the commodity component of the price is a dispatch factor to be agreed upon by the two parties. The dispatch

factor is intended to be a variable amount which allows NEP's gas-fired units to be competitive with other units in the NEPOOL system. The dispatch factor can be either a positive or negative number. Should agreement on the value of the dispatch factor not be possible, then it will take a value of zero. The dispatch factor can be redetermined if, for any consecutive six-month period, the average contract price was less than 90 percent of the AAMP or was such that NEP's units could not be fired at an average 90 percent net capability. Redetermination of the contract price is permitted beginning 1 November 1992 and every second year thereafter.

The estimated price at the Alberta border as of January 1990 under this contract was $ Cdn. 2.04/GJ ($ Cdn. 2.19/MMBtu).

14.3.3.4 Triton Canada Resources Limited

NEP and Triton signed a contract dated 31 August 1988 for the sale of 425 10^3m^3 (15 MMcf) of gas per day for a term of 20 years.

The contractual provisions regarding the remedies available should NEP's annual average take be less than 65 percent of the MDQ and off-system sales, are identical to those found in the NEP/Sceptre contract.

The commodity charge component of the price is calculated monthly and is 85 percent of the AAMP plus an incremental payment equal to one-half the TopGas levy. The incremental payment is not to exceed $ U.S. 0.05/GJ ($ U.S. 0.05/MMBtu) nor is it to extend beyond 31 August 1994.

Redetermination of the contract price is permitted under specific circumstances after 1 November 1993 and every two years following the last redetermination. NEP may request redetermination in the event that the contractual price would not have resulted in the dispatch of its gas-fired units at an average 80 percent net capability during any year. Triton may request redetermination if the contract price during any year was less than 85 percent of the price of Alberta-sourced gas sold for electric generation into New England.

The estimated price at the Alberta border as of January 1990 under this contract was $ Cdn. 1.55/GJ ($ Cdn. 1.67/MMBtu).

14.3.4 Regulatory Status

Each of NEP's producers applied to the AERCB in early 1989 for long-term removal permits.

At the time of the hearing, Sceptre's application was pending before the AERCB, but approval was expected shortly. Both Renaissance and Triton were awaiting Lieutenant Governor in Council approval. BP Resources had been granted removal permit GR90-90 by the AERCB.

BP Resources has also filed an application with the British Columbia Ministry of Energy, Mines and Petroleum Resources for a long-term energy removal certificate to remove gas from that province.

NEP stated that it had filed an application with the DOE/FE in February 1990 and that it anticipated authorization in the first quarter of 1991.

14.4 Views of Intervenors

Union characterized the NEP supply contracts as "talk and walk" type contracts. All four contracts require price redetermination at specified intervals and, should a price not be agreed upon, the contract can be terminated. Union submitted that these contracts were, therefore, in effect, short-term agreements with options for renewal and should not be relied upon to support a long-term export application.

Union opposed the export licence application by NEP and the related portion of the facilities application by TransCanada based upon the lack of both contractual assurances of takes and long-term gas sales contracts.

Union argued that the only contractual assurance of take was that the Canadian producers could reduce the DCQ should sales not occur above a certain level. Union stated that it does not consider demand charge obligations to be persuasive evidence that gas would flow.

Union also argued that, as in the Pawtucket/Columbia contract, these contracts contain no binding arbitration provisions and are thus essentially renewable short-term contracts.

In rebuttal, NEP argued that both the producers and NEP have a real and substantive incentive to keep gas flowing under the contracts for the full life of the applied-for licence. In particular, the bilateral right to compel renegotiation and the lack of binding arbitration was intended to force the parties to come to a market-based resolution of any pricing disputes. The high transactions and regulatory costs of obtaining a new supplier/purchaser and the risk of incurring transportation demand charges for unused capacity were seen as inhibiting the parties from recontracting with other parties.

14.5 Views of the Board

With respect to the NEP gas purchase contract with its producers, the Board agrees with Union that contracts which are terminable without any requirements for arbitration do not provide full assurance of viability over the life of an export licence. However, the Board does not agree that absence of an arbitration provision is sufficient reason to deny an export licence application.

The Board is prepared to accept NEP's evidence that the parties to the supply agreements have incentives to continue their respective dealings over the intended term. The producers have dedicated supply to the project, and NEP has a commitment to pay the demand charges on TransCanada over the life of a 15-year FS contract. Moreover, renegotiation provisions should ensure that the contracts will remain market responsive. The Board is willing to accept that, from the perspective of the participants in this export project, the prospect of losing either an attractive market opportunity or a reasonably priced, secure source of supply may prove a sufficient inducement to renegotiate contractual arrangements successfully.

The Board is satisfied with NEP's supply relative to the applied-for requirements for Triton, Renaissance and BP Resources and is further assured that any shortfalls that might occur could be alleviated by developing a portion of NEP's undiscovered potential.

The Board's analysis of Sceptre's corporate warranty supply indicates deficiencies commencing between the years 2000 and 2003. However, the Board is satisfied that Sceptre would be able to rely on its ongoing exploration program to satisfy a portion of its requirements over the latter part of the proposed export licence term.

The Board notes that transportation on all required systems has been arranged. The Board is satisfied that NEP's export proposal would recover all fixed costs of transportation in Canada. The Board notes that NEP is the shipper on TransCanada and is thus directly responsible for paying TransCanada demand charges.

The Board is of the view that the pricing provisions contained in the gas contracts permit adjustments in the export price to reflect changing market conditions. The Board also recognizes the flexibility that exists in the agreement through the inclusion of renegotiation provisions.

The Board notes that the applied-for gas would comprise roughly one-third of the volumes for use at the five power stations. In the Board's view, the fact that the gas could be used at any of the gas-burning facilities which NEP and its affiliates own, and that NEP is contracting for gas supply and transportation to meet average, rather than peak demand, would ensure adequate take levels under the gas sales contracts.

The Board has reviewed the gas contracts and has noted that they have been negotiated at arm's length between NEP and the four Canadian producers, and that the pricing terms are such that the arrangement is likely to be durable over the contract/licence term.

The Board notes that NEP is requesting a 15-year licence term despite the fact that three of the supporting gas sales agreements have 20-year terms. NEP explained that its producers preferred not to provide reserve inventories of 20 years to match the licence term.

The Board has not been persuaded by the arguments of Union that an export licence should not be granted to NEP. Specifically, although the Board does recognize the lack of contractual assurances of take and binding arbitration provisions, the Board has been persuaded by

NEP's arguments regarding the strength of its market. Further, the Board is of the view that it would be inappropriate to impose a "minimum take test" on export applications.

The Board notes that the Canadian producers have endorsed the proposed export by virtue of their having executed the gas contract.

The Board notes that NEP's application included a request for a sunset provision.

14.6 Decision

The Board has decided to issue a gas export licence to NEP, subject to the approval of the Governor in Council. Appendix IV contains the terms and conditions of the licence, including a condition that the term of the licence shall commence on 1 November 1991 and shall end on 1 November 1993, unless exports commence under the licence on or before 1 November 1993, in which case the term would expire 15 years following 1 November of the year in which such exports commenced.

Chapter 15

ProGas Limited

15.1 Application Summary

By application dated 8 August 1989, ProGas requested the Board, pursuant to subsection 21(2) of the Act, to amend natural gas export Licence GL-81 and authorize exports as follows:

Term	- from 1 November 1991, or the date of first delivery, to 31 October 2009 for a term of 18 years, six months
Point of Export	- near Iroquois, Ontario
Maximum Daily Quantity	- 708 $10^3 m^3$ (25.0 MMcf)
Maximum Annual Quantity	- 258 $10^6 m^3$ (9.1 Bcf)
Maximum Term Quantity	- 4 800 $10^6 m^3$ (169.5 Bcf)
Tolerances	- 10 percent per day and 2 percent per year

In the alternative, ProGas requested that the Board issue a new export licence pursuant to section 117 of the Act with terms and conditions identical to those above and to revoke gas export Licence GL-81 upon issuance of the new licence.

Gas export Licence GL-81 was issued by the Board to ProGas on 8 March 1983. This licence authorized the export of 20 197 $10^6 m^3$ (713 Bcf) to Texas Gas at Emerson, Manitoba. In December 1988 the Board approved the transfer of 5 170 $10^6 m^3$ (182.5 Bcf) from Licence GL-81 to a new gas export licence with a corresponding reduction in Licence GL-81's term volume. In December 1989, the Board approved a further amendment to Licence GL-81 and transferred 10 227 $10^6 m^3$ (361 Bcf) to a third new gas export licence. By its current application, ProGas has applied to export the remaining Licence GL-81 term volume of 4 800 $10^6 m^3$ (169.5 Bcf) to Granite State Gas Transmission Inc. ("Granite State") and MASSPOWER Joint Venture ("MASSPOWER") through their agent Orchard Gas Corporation ("Orchard Gas") for use at a cogeneration facility to be located at Springfield, Massachusetts.

The gas reserves dedicated to this export project would come from the province of Alberta and are part of ProGas' overall supply pool.

The cogeneration facility's power output would be sold to various New England electrical utilities and the thermal energy would be sold to Monsanto Company ("Monsanto").

The gas proposed for export would be transported on the systems of NOVA within Alberta and TransCanada to the international boundary at Iroquois, Ontario. From this point the gas would be transported by IGTS, Tennessee, Granite State and Bay State Gas Company ("Bay State") to the ultimate end-users.

15.2 Gas Supply

15.2.1 Supply Contracts

ProGas' gas supply is contracted from approximately 180 producers under two purchase programs. The original purchase program (ProGas I) was completed in 1978 with a term of 25 years. This program comprises about 40 percent of ProGas' remaining reserves.

The second purchase program (ProGas II) was completed in 1981, with a term of 25 years. This program comprises about 60 percent of ProGas' remaining reserves.

15.2.2 Reserves and Productive Capacity

ProGas is relying primarily on gas supply information previously submitted to the Board in the GH-7-88 and GH-1-89 proceedings. The Board notes that ProGas is also relying in part on gas supply information reviewed in the GH-6-81 proceeding. ProGas updated its estimate of remaining marketable reserves to 97 276 $10^6 m^3$ (3,434 Bcf), as of year-end 1988.

There is no increase in the term volume being requested in the current application and the maximum daily rate is being reduced. The Board also notes that no intervenors questioned the Applicant's gas supply in this proceeding. Based on the results of its previous reviews and the fact that the proposed exports do not represent an increase in the term volume previously authorized for export, the Board did not consider it necessary to conduct a further rigorous review of ProGas' reserves and productive capacity in this proceeding.

15.3 Market and Commercial Arrangements and Regulatory Status

15.3.1 Market

ProGas' proposed export of 708 10^3m^3 (25.0 MMcf) per day would be for use by the MASSPOWER cogeneration facility and represents approximately 50 percent of the plants fuel requirements. Until such time as the MASSPOWER facilities are completed, Granite State would be the sole purchaser of the gas, and once deliveries have commenced to MASSPOWER, is also committed to serve as a backstop market to ProGas for up to 75 percent of the DCQ with the right to purchase all volumes up to the total DCQ if they are not purchased by MASSPOWER.

Granite State would sell its share of the gas to two LDCs, Bay State and Northern Utilities Inc. ("Northern Utilities"), which are affiliated companies, as a part of their system supply requirements for markets in Massachusetts, New Hampshire and Maine. Bay State and Northern Utilities have large underground storage capability, extensive LNG facilities, including liquefaction capability, and a large interruptible customer base. Bay State is primarily a gas distribution utility which provides service to approximately 225,000 customers in a combined service area encompassing approximately 1,650 squares miles.

ProGas stated that investors of MASSPOWER project have spent approximately $ U.S. 6.5 million so far. The remaining $ U.S. 164 million would be spent before the start-up date.

The 240 MW MASSPOWER cogeneration plant, which is expected to be in commercial operation by October 1992, will be located at the Monsanto Indian Orchard Plant on a six-acre site leased from Monsanto, in Springfield, Massachusetts. The MASSPOWER facility would provide Monsanto with supplementary steam supply at reduced costs. The project's financing is in the process of finalization and is expected to be in place by October 1990.

Electrical output from the cogeneration plant will be sold to various private and public New England utilities.

15.3.2 Transportation

Within Alberta, the gas would be shipped to Empress, Alberta on the NOVA system under existing firm and interruptible agreements between ProGas and NOVA. ProGas has also submitted requests for additional firm capacity. ProGas submitted a letter of intent from NOVA dated 9 June 1989 indicating NOVA's willingness to transport the gas contingent upon its being able to modify or construct facilities.

ProGas and TransCanada have entered into a precedent agreement dated 1 May 1989 as amended 24 January 1990, for firm service transportation from Empress, Alberta to the export point at Iroquois, Ontario.

From Iroquois, Ontario the gas would be transported in the U.S. on the systems of IGTS and Tennessee under firm service agreements for which MASSPOWER has entered into precedent agreements both dated 16 December 1988. The gas transported through IGTS would be transferred to Tennessee's system at Wright, New York for delivery to Bay State at Monson, Massachusetts. Bay State would, in turn, deliver the gas to Granite State for ultimate delivery to MASSPOWER in Springfield, Massachusetts. MASSPOWER and Bay State currently have applications before the Massachusetts Energy Facility Siting Council to authorize this service.

15.3.3 Gas Sales Contract

A precedent agreement dated 1 May 1989, as amended 15 March 1990, was executed between ProGas and Orchard Gas, as agent for Granite

State and MASSPOWER. The contract provides for up to 708 10^3m^3 (25.0 MMcf) per day of gas for an initial period of 15 years, commencing on or about 1 November 1991. The contract is renewable upon mutual agreement.

Granite State would be the sole purchaser of the gas until the MASSPOWER facilities are completed. Granite State is committed to purchase up to 75 percent of the DCQ.

The contract includes a two-part pricing structure consisting of a monthly demand charge and a commodity charge. The demand charge component consists of the sum of the NOVA and TransCanada fixed costs of transportation plus ProGas' cost of service.

The commodity charge is structured as a field price (which would be adjusted over time) plus all variable transportation costs such as fuel costs on NOVA and TransCanada. The field price is set at \$ U.S. 1.61/GJ (\$ U.S. 1.70/MMBtu) and, beginning in 1989, would be varied monthly by applying the change in the NEPOOL three-month rolling average fossil fuel index which is based upon forecasts of prices for gas, coal and oil required to serve forecasted generating capacity in NEPOOL's service area. The selective weights of the fuels used in the index are currently 15 percent for gas, 25 percent for coal and 60 percent for oil.

The estimated price at the Alberta border as of January 1990 under this contract was \$ Cdn. 2.325/GJ (\$ Cdn. 2.49/MMBtu).

Either party may, upon written notice, request renegotiation of the pricing terms in any year. In the event parties are unable to agree to a price, either party has the option, every three years, of going to arbitration.

In the event that the annual triggering quantity of 75 percent of the annual contract quantity is not purchased in any contract year, then Granite State/MASSPOWER would be required to purchase the annual triggering quantity plus any deficiency volumes from the preceding contract year. In the event buyer does not purchase this volume, then seller may reduce the DCQ.

Further, MASSPOWER and Granite State have also entered into an agreement whereby MASSPOWER would sell to Granite State, when available, volumes in excess of the minimum 75 percent DCQ level.

ProGas stated that the combination of proven efficiency of combined cycle technology, the pricing formula and the ability to sell volumes not taken by the cogeneration facility to Granite State, leads it to believe gas will be taken under this contract at approximately 90 percent.

15.3.4 Power Sales Agreements

The MASSPOWER project is a QF facility and will be selling electric power and energy to the following buyers: Massachusetts Municipal Wholesale Electric Company ("MMWEC"), under two contracts, versions "A" and "B"; the Boston Edison Company ("BEC"); the Commonwealth Edison Company ("CEC"); and the Western Massachusetts Electric Company ("WMECO"). With the exception of sales to WMECO and MMWEC, contract version "A", all the contracts require wheeling over the transmission facilities of Northeast Utilities Service Company ("NU"). NU is a holding company that controls WMECO. The cogeneration project will interconnect with WMECO at a point adjacent to the Monsanto plant.

The power sales agreements with CEC and WMECO have not yet been filed with the Board. MASSPOWER has undertaken to file the outstanding contracts upon their execution by the parties concerned.

15.3.4.1 Massachusetts Municipal Wholesale Electric Company

Sales to MMWEC are pursuant to two separate but virtually identical contracts. Version "A" of the agreements is for sales requiring no wheeling, whereas sales under version "B" do require wheeling. Of the cogeneration plant's total net electrical capability, 7.86 percent or 17.685 MW would be sold under the two agreements, "A" and "B". Electrical sales to MMWEC under agreement "A" would be made to the towns of Littleton (3.0 MW) and to Holyoke (7.645 MW). Sales under agreement "B" would be made to Asburnham (0.6 MW), Croton (1.3 MW), Wakefield (2.717 MW) and to Ipswich (2.423 MW). Both agreements would be in effect for a period of 20 years

following commencement of commercial operations. Following termination, MMWEC has a 60 day-option to purchase a share equal to its initial entitlement at a price no greater than that offered to any other entity.

The MASSPOWER plant would be dispatched on a least-cost basis by NEPEX, the operating arm of NEPOOL. The price of electricity to MMWEC is comprised of monthly charges for operations, capacity, fixed fuel transportation, energy and security. Capacity charges are targeted at an 85 percent availability factor. Capacity payments apply whether or not the plant is dispatched. Sales under MMWEC "B" include a charge for transmission attributable to the buyer. Should the plant be dispatched at less than a 60 percent capacity factor over a two-year period, then the parties agree to seek must-run status from NEPOOL. Should QF status be lost, then rates could be no higher than those provided for in the agreements.

15.3.4.2 Boston Edison Company

Sales to BEC are pursuant to the power purchase agreement executed with MASSPOWER and dated 15 October 1990. Power deliveries may have commenced under other power contracts, but the commencement date of operation with BEC is not effective before 1 January 1994. BEC's entitlement is 44.34 percent of the cogeneration plant's net capability, but not to exceed 100 MW in summer nor 117 MW during the winter. The agreement would have an initial term of 20 years following the commencement of commercial operations. NEPEX would dispatch the plant based on a least-cost basis.

BEC payments for electricity include payments which are made regardless of whether BEC takes any electric energy. Wheeling charges are paid by MASSPOWER. If the price of electricity from MASSPOWER is sold to third parties at a more favourable rate, then, except for sales outside the NU transmission system, BEC is entitled to similar terms and conditions. If the cogeneration facility is expanded, BEC has a right of first refusal to a proportional amount of the output. In the event that MASSPOWER was unable to operate the plant, BEC could take possession of the plant and operate and control it until such time as MASSPOWER regains its ability to operate.

15.3.4.3 Commonwealth Edison Company

MASSPOWER has undertaken to file the electric power purchase agreement with CEC upon its execution.

15.3.4.4 Western Massachusetts Electric Company

MASSPOWER has undertaken to file the electric power purchase agreement with WMECO upon its execution.

The unexecuted CEC and WMECO contracts represent approximately 33 percent of the cogeneration facility's output.

15.3.5 Transmission Service Agreement

The transmission service agreement, dated 18 October 1990, was executed between NU and MASSPOWER. NU acts as agent on behalf of WMECO and the Connecticut Light and Power Company in the matter of providing firm transportation service for part of the electrical output from the MASSPOWER cogeneration facility. NU's obligation to transmit is contingent upon the receipt by WMECO of electricity from the cogeneration project.

The contract is in effect for a term of 20 years from the commercial operation date for any of MASSPOWER's power purchasers or from 1 December 1993. The contract may be extended for up to an additional five years. Contracted amounts are for 186 MW in the summer and 215 MW in the winter.

15.3.6 Thermal Energy Sales Agreement

The proposed sale of thermal energy would be pursuant to an agreement, dated 30 July 1990, between MASSPOWER and Monsanto. The agreement would continue for a 20-year period, commencing on the date when electric power purchasers claim capability from the facility. Renewal of the agreement is determined in conjunction with negotiations for extensions of the lease/service agreements between Monsanto and MASSPOWER. Monsanto is required to take sufficient steam to enable the cogeneration plant

to maintain its QF status. The steam purchased would replace steam that would otherwise be generated by an existing Monsanto coal-fired boiler.

The price for steam is designed to provide MASSPOWER with a payment that reflects Monsanto's alternative cost of coal. If Monsanto's steam requirements are reduced, Monsanto is not required to reduce its own essential steam generation. Should reduction of steam take have an adverse impact on the cogeneration facility, the parties would cooperate to develop new steam requirements to maintain QF status. The cost to develop new steam requirements would be shared between the parties. If new steam requirements are not developed, the parties would share the incremental costs to operate as a non-QF facility. In both cases Monsanto's costs are limited to $ 2.5 million.

15.3.7 Regulatory Status

ProGas would remove its volumes from Alberta under permit GR 86-71D as amended by the AERCB on 3 May 1990. This amendment allows ProGas to remove an additional 708 10^3m^3 (25.0 MMcf) per day for a 15-year term commencing 1 November 1991.

Orchard Gas, on behalf of MASSPOWER and Granite State, obtained DOE/FE import authorization on 15 November 1990.

The MASSPOWER facility received QF status from the FERC on 25 May 1989.

15.4 Views of the Board

The Board is satisfied as to the adequacy of ProGas' supply relative to its applied-for requirements on the basis of supply information examined in previous hearings.

ProGas filed with the Board the steam agreement with Monsanto as well as power sales agreements with MMWEC and BEC. The Board notes that the power sales contracts with WMECO and CEC are expected to be concluded shortly. The Board is satisfied that the downstream markets for electricity and steam produced by the cogeneration facility are secure and that the facility would operate at a high load factor, especially in light of the "backstopping" which will be provided by Granite State.

The Board notes that project financing for the MASSPOWER cogeneration facility is in the process of finalization and all MASSPOWER's downstream facility authorizations, for IGTS, Tennessee, the DOE/FE import authorization, and all of MASSPOWER's site-related permits such as state approvals for siting, local distribution facilities, and transportation service, have been received.

The Board notes that ProGas requested an amendment to gas export Licence GL-81 or, alternatively, a new licence. In either event, it requested a term of 18.5 years. ProGas cited several reasons for this request, including the provision in the gas sales contract to extend the 15 year term for an additional 5 years and the steam and site lease agreement which has an initial 20-year term, In addition, the remaining volume licensed under GL-81 would satisfy delivery obligations at 100 percent load factor for the 18.5 year term.

The Board considers that it would be appropriate to issue a licence for 18.5 years with a term volume of 4 800 10^6m^3 (169.5 Bcf) and that gas export Licence GL-81 be revoked.

The Board has reviewed the terms and conditions of the ProGas gas sales contract with Orchard Gas. The contract's pricing provisions include a two-part rate consisting of a monthly demand charge and a commodity charge.The Board is satisfied that under the terms of the contract, the demand charge component of the export price would ensure recovery of all fixed costs of transportation in Canada. The commodity component of the price is structured as a field price, which would be adjusted over time, plus all transportation variable costs (such as fuel and non-gas pipeline commodity costs) associated in moving gas to the point of delivery. The field price is indexed to a forecast of gas, coal and oil prices and a forecast of requirements from the different generating capacities available to NEPOOL. The Board finds that the index used to escalate base price in the contract would reflect changing market conditions. The Board is satisfied that the gas sales contract was negotiated at arm's length.

Finally the Board notes that MASSPOWER's requirement for natural gas which stems from the need for new electric power generation facilities in the U.S. northeast, provides good assurance that the natural gas volumes proposed to be exported would be taken at a high load factor.

15.5 Decision

The Board has decided to issue a gas export licence to ProGas, subject to the approval of the Governor in Council. Appendix IV contains the terms and conditions of the licence, including a condition that the term of the licence shall commence on 1 November 1991 and shall end on 1 November 1993, unless exports have commenced under the licence on or before 1 November 1993, in which case the term would end on 30 April 2010.

Chapter 16

Unigas Corporation

16.1 Application Summary

By application dated 1 December 1989, as amended, Unigas sought, pursuant to Part VI of the Act, a natural gas export licence for sales to RG&E with the following terms and conditions:

Term	- commencing on the date of first deliveries for a term of 10 years
Point of Export	- near Chippawa, Ontario
Maximum Daily Quantity	- 453 10^3m^3 (16.0 MMcf)
Maximum Annual Quantity	- 166 10^6m^3 (5.8 Bcf)
Maximum Term Quantity	- 1 654 10^6m^3 (58.7 Bcf)

The volumes would be supplied by Mark Resources Inc. ("Mark"), a subsidiary of Unigas, from its reserves located in British Columbia, Alberta and Saskatchewan.

The gas would be transported in British Columbia by Westcoast, in Alberta by NOVA and in Saskatchewan by TransGas. From the interconnections with the TransCanada system, the gas would be transported by TransCanada to the international boundary near Chippawa, Ontario. In the U.S., the volumes would be delivered to RG&E by Empire.

RG&E is a natural gas distribution and electric utility serving Rochester and surrounding counties in western New York State. The company intends to use the proposed export volumes as part of its system supply.

16.2 Gas Supply

16.2.1 Supply Contracts

Unigas has executed a gas supply contract with Mark for a term of ten years. Mark has contractually dedicated specific lands in British Columbia, Alberta and Saskatchewan to the performance of the contract. These lands also include reserves under the control of PreCambrian Shield Resources Limited ("PreCambrian"), a subsidiary of Mark.

16.2.2 Reserves

Table 16-1 shows that the Board's estimate of Unigas' remaining marketable gas reserves is eight percent lower than Unigas' estimate. The Board's estimate, however, exceeds the applied-for term quantity by 67 percent.

The discrepancy between estimates of reserves by Unigas and the Board can largely be attributed to four fields, with the majority of the variance in estimates of reserves attributable to the Niton Field.

The Board's estimate of net pay and area differed from that of Unigas in the Niton area. The Board did not recognize a portion of Unigas' probable reserves due to a different geological interpretation of the pool area.

The remainder of the overall difference arose primarily from area assignments for single-well pools and, to a lesser extent, variation in other reservoir parameters.

The Board's analysis recognized 56 gas pools, of which 84 percent are not producing. Seventy-three percent of the pools for which Unigas submitted reserves have reserves estimated by the Board to be smaller than 100 10^6m^3 (3.5 Bcf) of initial marketable gas. The majority of the Alberta and Saskatchewan pools are located in Cretaceous sands, while British Columbia pools are found in Triassic and Permian horizons.

Table 16-1

Comparison of Estimates of Unigas' Established Gas Reserves With the Applied-for Volume

10^6m^3 (Bcf)

Unigas[1]	NEB[2]	Applied-for Volume
2 997 (106)	2 758 (97)	1 654 (58)

1. As of 31 December 1989.
2. As of 31 December 1988.

In summary, the Board's estimate is lower than Unigas' estimate but is significantly higher than the applied-for volume.

16.2.3 Productive Capacity

A comparison of the Board's and Unigas' estimates of productive capacity with the applied-for requirements is shown in Figure 16.1.

Unigas projected productive capacity from 22 different areas in British Columbia, Alberta and Saskatchewan. Unigas' projections of productive capacity from these areas utilized either production, drill stem or absolute open flow test data, where available. In cases where this information was not available, an initial rate-of-take of 1:5 000 was utilized and productive capacity was then declined exponentially from this initial level at a rate consistent with the production characteristics of similar zones. Unigas indicated that it would maintain productive capacity in excess of its requirements throughout the term of its proposed export licence.

Unigas further submitted that this export was a small component of its total sales and was confident it would have no difficulty alleviating any potential shortfalls in deliverability from other Unigas supply sources.

The Board's estimate of productive capacity also indicated that Unigas is capable of meeting its applied-for requirements throughout the term of the proposed licence.

16.3 Market and Commercial Arrangements and Regulatory Status

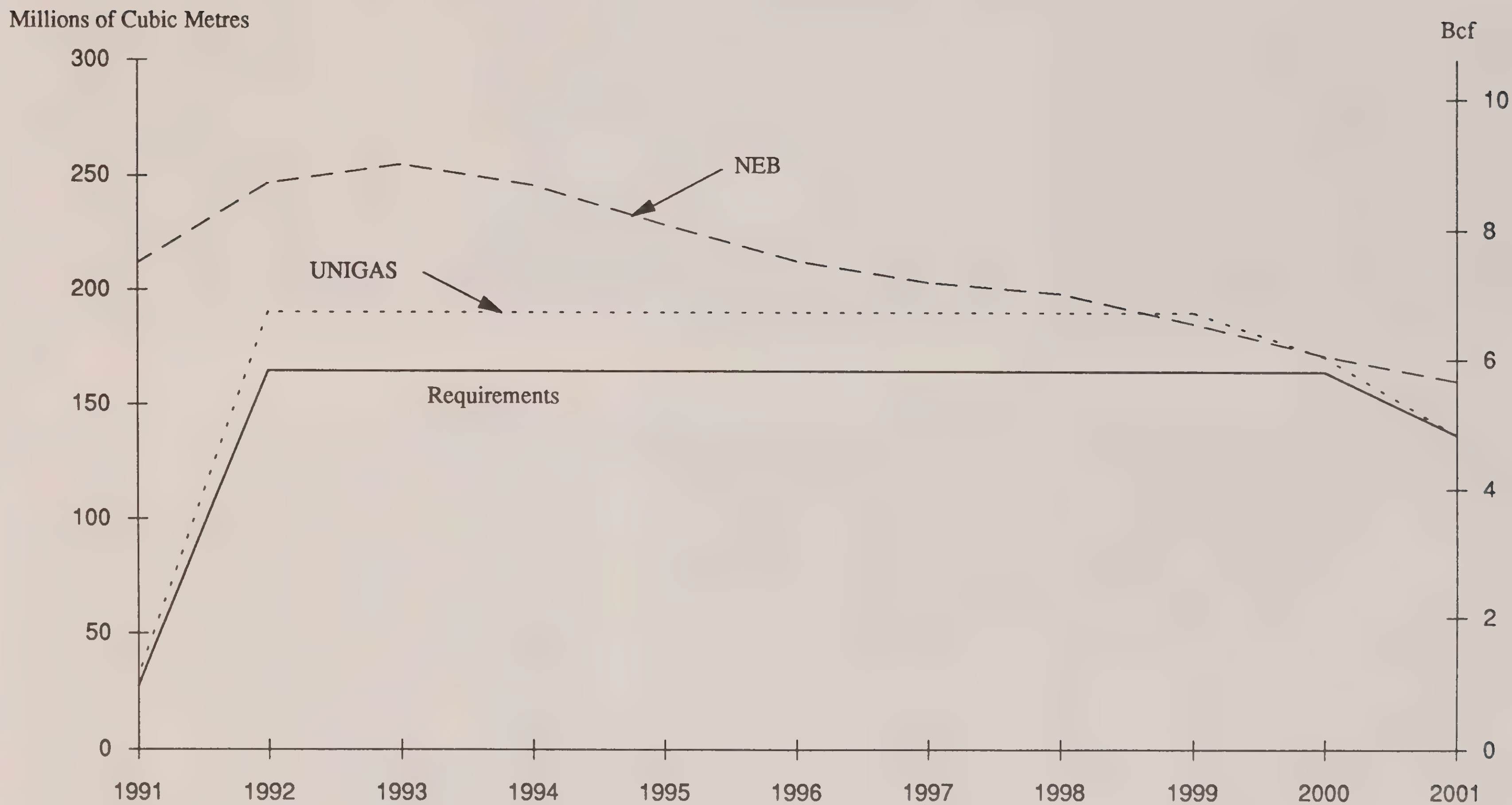
16.3.1 Market

RG&E is a natural gas distribution and electric utility serving approximately 260,000 customers in a geographical area comprising the City of Rochester and parts of seven surrounding counties in western New York State. The company's territory has a population of about 900,000.

The gas distribution system, which uses approximately 1 415 10^6m^3 (50 Bcf) on an average annual basis, serves a diversified industrial and commercial customer base including medical, academic and high technology organizations. RG&E also provides a transportation service for third parties. Current allocation of RG&E's natural gas requirements by customer class is as follows:

Figure 16.1

COMPARISON OF ESTIMATES OF ANNUAL PRODUCTIVE CAPACITY FOR UNIGAS



Customer Class	Percentage
Residential	57
Commercial	20
Industrial	17
Municipal	6

The company provided a forecast of sales for the upcoming five years indicating that consumption would increase by about 28 $10^6 m^3$ (1 Bcf) or 1.5 percent during the period. The commercial market was projected to be the strongest area of growth followed by the residential sector. The proposed export volumes would comprise about 12 percent of RG&E's total requirements and be used as base load supply. It was expected that the Canadian gas would be taken at a load factor in excess of 90 percent.

Currently, RG&E is dependent upon CNG for most of its system supply requirements and for all transportation and does not have any storage of its own. RG&E has begun a major initiative to diversify its natural gas supply, transportation and storage, in order to lessen its dependence on CNG. The company noted that U.S. natural gas policy has changed in recent years, allowing competitive forces to work in the marketplace. In particular, it was observed that producer prices have essentially been deregulated making it possible for an LDC such as RG&E to purchase directly from producers, and to pay pipelines for transporting the supplies.

In this environment, RG&E has been actively pursuing new gas supplies together with alternative transportation arrangements. It was indicated that negotiations for U.S. sources of supply totalling about 2 875 $10^3 m^3/d$ (101.5 MMcfd) were currently underway. These would be transported to ANR operated storage facilities in Michigan. The U.S. volumes and the proposed Canadian gas imports would be delivered to RG&E's city gate through the proposed Empire pipeline, to be constructed in the U.S. from the international boundary at Chippawa, Ontario, to Rochester and the Syracuse area (for a description, see section 16.3.3).

RG&E said that, pursuant to the terms of its contract, it anticipated being able to reduce its obligation with CNG to accommodate the new supply arrangements.

16.3.2 Transportation

The proposed export volumes would initially come from Saskatchewan and Alberta, the daily volumes being 283 $10^3 m^3$ (10.0 MMcf) and 170 $10^3 m^3$ (6.0 MMcf) respectively. Commencing in November 1993, 57 $10^3 m^3/d$ (2.0 MMcfd) of British Columbia production would replace an equivalent volume of Alberta supply. In British Columbia, the gas would be transported by Westcoast, in Alberta by NOVA and in Saskatchewan by TransGas. From the interconnections with the TransCanada system, the gas would be transported by TransCanada to the international boundary near Chippawa, Ontario. In the U.S., the volumes would be delivered to RG&E by Empire.

Under the terms of the gas purchase agreement between Unigas and Mark, Mark has responsibility for contracting for firm capacity on the pipeline systems of NOVA, Westcoast and TransGas. The purchase agreement stipulates that the arrangement for the NOVA service would be transferred and assigned by Mark to Unigas. For the firm service on Westcoast and TransGas, there would be no transfer or assignment to Unigas. The Applicant indicated that 127 $10^3 m^3/d$ (4.5 MMcfd) is available now on NOVA and the remaining 42 $10^3 m^3/d$ (1.5 MMcfd) would be available on 1 November 1992. In the event that the full 170 $10^3 m^3/d$ (6.0 MMcfd) is required prior to 1 November 1992, Unigas has existing NOVA capacity which could be used to bridge the Alberta transportation. With respect to TransGas capacity, firm service would be available on 1 November 1991. In British Columbia, Mark expects capacity to be available by 1 November 1993. It was indicated that the NOVA and TransGas pipeline systems would require expansion to transport the proposed export volumes.

On TransCanada, the gas would be shipped from Empress, Alberta to Chippawa, Ontario and two firm service contracts are required. The Empress, Alberta to Kirkwall, Ontario portion is the subject of a section 71 application by RG&E, discussed in chapter 27 of these Reasons. For the transport of gas from Kirkwall to Chippawa, Ontario, RG&E has executed a precedent agreement dated 5 October 1989 with TransCanada. Related to

this, it would be necessary for TransCanada to construct an extension to its facilities, known as the "Blackhorse Extension". This is the subject of a separate hearing.

In the U.S., the gas to be exported to RG&E would be transported from the international boundary to the city of Rochester via Empire, under an executed, amended and restated precedent agreement between RG&E and Empire dated 7 May 1990. Empire is owned by subsidiaries of The Coastal Corporation and Union Enterprises (40 per cent each) and by RG&E (20 per cent). The precedent agreement with Empire provides for firm daily transportation of not less than 3 328 10^3m^3 (117.5 MMcf) in the first contract year, increasing to not less than 6 138 10^3m^3/d (216.7 MMcfd) in the third contract year, of which the proposed daily export of 453 10^3m^3 (16.0 MMcf) of western Canadian gas would be a portion.

The Empire project represents part of the project designed to permit RG&E to diversify its sources of supply. As mentioned under the section on markets, this involves the purchase by RG&E of U.S.-sourced gas which would be transported to storage facilities in Michigan. The transportation for this is the subject of an application pursuant to paragraph 8(1)(e) of the Part VI Regulations by RG&E to import 2 875 10^3m^3/d (101.5 MMcfd) of U.S.-sourced gas into Canada at a point near St. Clair, Michigan, for re-export at Chippawa, Ontario and subsequent delivery to the city of Rochester on Empire. An application to construct Empire is currently pending before the NYSPSC to determine whether a certificate of environmental compatibility and public need should be issued.

16.3.3 Gas Sales Contract

In its role as the party responsible for arranging for the purchase of gas supplies and for the sale of the gas to RG&E, Unigas executed a gas purchase agreement dated 18 January 1989 with its producer and subsidiary, Mark, and executed a gas sales contract dated 29 November 1989 with RG&E. The terms and conditions of the arrangement governing the export of the gas are essentially those included in the gas sales contract between Unigas and RG&E.

The agreement includes several conditions precedent such as the requirements that buyer and seller obtain the necessary regulatory import and export authorizations and arrange for transportation. If, by 1 November 1991, the conditions precedent are not satisfied, either party has the right to terminate the agreement on 30 days written notice.

The gas sales contract, which extends for a term of ten years, provides for extensions of the arrangement for additional terms of five years, subject to negotiation at least 12 months prior to the expiry of the contract. The daily contract quantity is 453 10^3m^3 (16.0 MMcf) and the annual contract quantity is 165 10^6m^3 (5.8 Bcf). If in any month RG&E fails to purchase 85 percent of the monthly contract quantity ("MCQ"), RG&E would pay Unigas for the demand charges on NOVA, Westcoast and TransGas, up to the 85 percent level regardless of the actual volume of gas taken. The agreement also states that RG&E would not substitute other western Canadian supplies for Unigas volumes in any month that quantities purchased from Unigas fall below 85 percent of the MCQ.

The contract stipulates that Unigas, and its producer, Mark, have the financial responsibility for paying the demand charges on NOVA, Westcoast and TransGas. RG&E is responsible for the demand charges on TransCanada and on Empire.

Under the terms of the contract, the monthly contract price is equal to the monthly Rochester inlet price, less the monthly Empire toll, less the monthly TransCanada toll, less the monthly performance incentive
where:

- the monthly Rochester inlet price is equal to $ U.S. 2.77/GJ ($ U.S. 2.92/MMBtu) multiplied by the monthly base price indexer;

- the monthly base price indexer reflects an average of: the monthly prices used by Alberta to determine Crown royalties; the average monthly prices of Mid Continent Gas, as published by the FERC; and the weighted average price of firm sales to RG&E under contracts having a term of six years or more; and

- the monthly performance incentive is the reduction in price if the volumes taken are in excess of 85 percent of the MCQ. This is approximately $ U.S. 0.01/GJ ($ U.S. 0.01/MMBtu) for each multiple of five percentage points taken in excess of 85 percent.

The contract provides for a maximum price of 107 percent of the consolidated commodity price, which is the price filed with the FERC by CNG for volumes sold to RG&E. There are stipulations as to the number of months that this maximum price can be charged.

The contract provides for price redetermination for excess transportation tolls. In particular, if the combined TransCanada and Empire toll exceeds $ U.S. 1.00/GJ ($ U.S. 1.08/MMBtu) as of the date of first delivery either party may request a renegotiation of the Rochester inlet price. If the parties cannot agree within 30 days, the Rochester inlet price would be adjusted by 50 percent of the difference between the combined toll and $ U.S. 1.00/GJ ($ U.S. 1.08/MMBtu). In a situation where the combined toll exceeds $ U.S. 1.25/GJ ($ U.S. 1.35/MMBtu) as of the date of first delivery, Unigas can request RG&E to renegotiate the Rochester inlet price. If the parties cannot agree, Unigas may terminate the contract on six months notice.

Unigas provided information to illustrate how the contract prices would have been calculated in 1989. The average annual price, in western Canada (e.g., at Empress), would have been $ Cdn. 1.98/GJ ($ Cdn. 2.13/MMBtu), ranging from a high of $ Cdn. 2.17/GJ ($ Cdn. 2.34/MMBtu) in December to a low of $ Cdn. 1.92/GJ ($ Cdn. 2.07/MMBtu) in August.

The estimated price at the Alberta border as of January 1990 under this contract was $ Cdn. 2.40/GJ ($ Cdn. 2.59/MMBtu).

16.3.4 Regulatory Status

Applications for energy removal authorizations were made to the provinces of British Columbia, Alberta and Saskatchewan. The Saskatchewan Department of Energy and Mines sent letters to Mark and PreCambrian indicating that it had recommended that the removal permits be granted.

Unigas indicated that its British Columbia and Alberta authorizations were pending and were expected in early 1991.

RG&E applied for DOE/FE import authorization on 22 January 1990.

16.4 Views of Intervenors

CNG recommended that if a licence was to be granted by the Board, it should include a condition requiring Unigas to provide satisfactory evidence of import authorization. Unigas disputed the need for such a condition on the grounds that this is already required before TransCanada is permitted to build any facilities in Canada. Unigas stated that it would not object to the inclusion of a sunset clause in the licence.

With respect to downstream transportation arrangements, CNG recommended that the licence, if granted, should be conditioned to require Unigas to provide satisfactory evidence of firm transportation arrangements downstream of Chippawa. Unigas took the position that this would not be necessary in view of the fact that such evidence is already required before TransCanada may build facilities in Canada. In addition, as previously mentioned, Unigas would not object to a sunset clause being included in the licence.

16.5 Views of the Board

The Board is satisfied as to the adequacy of supply relative to Unigas' requirements.

In view of the fact that Unigas and Mark are responsible for payment of demand charges on NOVA, Westcoast and TransGas, and that RG&E would pay demand charges associated with the transportation on TransCanada, the Board is satisfied that the proposed export would recover Canadian transportation costs.

The Board notes that the price of the gas to be exported would escalate over time on the basis of average market prices for Alberta gas, U.S. mid-continent short-term gas prices, and the price of gas sold to RG&E under firm service contracts in

excess of six years. Based on this, the Board is of the view that the contractual pricing provisions would permit adjustments in the export price to reflect market conditions.

The terms of the contract prohibit RG&E from replacing the Unigas volumes with other western Canadian gas to any significant degree. In addition, the pricing provisions include a monthly performance incentive which reduces the price if RG&E takes are in excess of 85 percent of the MCQ as well as a price cap which should ensure that the export price remains competitive. These reasons, in addition to the commitment to pay Canadian demand charges, lead the Board to conclude that there is a reasonable assurance that the proposed export would operate at a high load factor.

Evidence of producer support was provided by way of an executed gas purchase agreement between Unigas and Mark.

Finally, with respect to CNG's proposal that a licence granted to Unigas should be conditioned with respect to the proposed date on which gas exports could commence, the provision of satisfactory evidence in respect of downstream transportation arrangements and U.S. import authorization and a sunset clause, the Board is of the view that only a sunset clause need be included in the licence.

16.6 Decision

The Board has decided to issue a gas export licence to Unigas, subject to the approval of the Governor in Council. Appendix IV contains the terms and conditions of the licence, including a condition that the term of the licence shall commence on the date of first deliveries and shall end on 1 November 1993, unless exports have commenced under the licence on or before 1 November 1993, in which case the term would end ten years following the date of first deliveries.

Chapter 17

Western Gas Marketing Limited

17.1 Application Summary

By application dated 8 November 1989, WGML sought, pursuant to Part VI of the Act, a natural gas export licence with the following terms and conditions:

Term	- commencing on the date of first deliveries and extending for a term of 15 years.
Point of Export	- near Niagara Falls, Ontario
Maximum Daily Quantity	- 283 10^3m^3 (10.0 MMcf)
Maximum Annual Quantity	- 104 10^6m^3 (3.7 Bcf)
Maximum Term Quantity	- 1 552 10^6m^3 (54.8 Bcf)
Tolerances	- 10 percent per day and 2 percent per year.

The proposed export volumes would be produced from fields within Alberta and supplied by WGML from TransCanada's contracted reserves. The gas would be transported on NOVA and TransCanada to the international border near Niagara Falls, Ontario. The gas would then be shipped on the systems of Tennessee, National Fuel, and Transco for final delivery to Elizabethtown Gas Company ("Elizabethtown"), a New Jersey LDC.

17.2 Gas Supply

An extensive review of WGML's supply was conducted coincidentally by the Board for the GH-5-89 and GH-6-89 proceedings. The Board's analysis of WGML's supply contained herein is essentially unchanged from that which was presented in the GH-6-89 Reasons for Decision.

17.2.1 Reserves and Supply Contracts

As WGML's gas supply would be obtained from TransCanada's general supply pool, all references in this Chapter to WGML's gas supply, lands, etc. relate to TransCanada's contracted supply pool. WGML provided an estimate of TransCanada's established reserves to be used to meet both existing commitments and the proposed export. Table 17-1 shows that the Board's estimate of WGML's reserves is approximately 19 percent lower than the estimate provided by WGML.

During its review of WGML's reserves submission, the Board noted that WGML had not submitted reserves estimates for a number of pools which appeared to be under its control. WGML was requested to review these pools and subsequently has advised the Board that AERCB reserves estimates should be used for them until WGML has an opportunity to review the pools more thoroughly. The Board has included these pools in its estimate of WGML's reserves because they appear to be under WGML's control.

In its analysis of WGML's gas supply, the Board recognized approximately 8 000 pools, almost all of which are in Alberta. They are distributed across most of the province and include all major producing horizons. Most of the pools are in Cretaceous zones in central and east-central Alberta. The Jurassic to Carboniferous zones include about 600 pools and are largely located in the Foothills area and north of the Deep Basin. The Devonian pools are fewer in number but contain fairly large reserves. These pools are located in the central and northern areas of Alberta.

Approximately 54 percent of WGML's reserves are contained in 100 pools, each with initial established reserves in excess of 3 000 10^6m^3 (106 Bcf). In contrast, only 16 percent of WGML's reserves are contained in approximately 6 700 small pools with initial established reserves less than 100 10^6m^3 (3.5 Bcf).

Differences in the Board's and WGML's estimates of reserves arise primarily from:

Table 17-1

Comparison of Estimates of WGML's Established Gas Reserves With the Applied-for Volume

10^9m^3 (Tcf)

WGML[1]	NEB[2]	Applied-for Volume[3]
645.6 (22.8)	520.6 (18.4)	1.6 (0.06)

1. As of December 1988. This estimate of reserves includes AERCB estimates for numerous small pools which are on WGML lands but for which WGML has not submitted an estimate of reserves. Without inclusion of these pools, the WGML estimate is 595.7 10^9m^3 (21.0 Tcf).
2. As of December 1988.
3. This represents only a very small portion of WGML's total requirements.

(a) differences in the geological and engineering assessment of reserves for specific pools; and

(b) differences in the interpretation of WGML's contracted lands position.

The Board's estimates of reserves for a number of larger pools are lower than those of WGML, in part because performance data for some of these pools would not appear to substantiate WGML's reserves estimates based on volumetric analysis. Other reasons for these differences in estimates of reserves for large and medium sized pools relate to interpretations of recovery factor, pool size and various reservoir parameters.

A further difference between the Board's and WGML's estimates of reserves arises from the approach to reserves estimation for single-well pools. WGML generally adopts an area assignment of 256 hectares (one section) to estimate reserves for a single-well pool. WGML stated that it uses a smaller single-well area where experience and knowledge support such action. As outlined in previous sections of these Reasons, the Board uses a variable area assignment, usually ranging from 150 hectares to 259 hectares or greater but most often uses 200 hectares for a single-well pool. Due to the large number of single-well pools in the WGML reserves portfolio, the difference in approach to reserves estimates for single-well pools leads to a significant difference in overall reserves estimates. Differences in reserves attributed to single-well pools also arise from the cumulative effect of small differences in other reservoir parameters.

WGML also tends to coalesce several small pools into one larger pool, which often has the effect of increasing the overall WGML estimate of reserves. While the Board attempted to review the geological interpretation for many of these pools, it remained, in some cases, unable to agree with WGML's assessment and therefore adopted a somewhat lower estimate of reserves.

The Board and WGML also use somewhat different approaches to determine cumulative production and, hence, remaining reserves for WGML producing interests. WGML determines its remaining reserves for a pool by deducting cumulative production from dedicated lands from WGML's initial marketable reserves. While WGML undoubtedly is in the best position to determine its cumulative production from

dedicated lands, this approach can have the effect of distorting the estimate of remaining WGML reserves for the pool if production by WGML to date has not been in proportion to WGML's overall interest in the pool. The Board's estimate of WGML's remaining reserves is obtained by applying WGML's percent control to the remaining reserves for the pool. Remaining reserves for the pool are determined by deducting cumulative pool production from initial reserves. This approach assumes that remaining production would be in proportion to the ownership interests in the pool and, with the data available to the Board, is the only viable means of assigning remaining reserves to specific producer interests.

During its assessment of WGML's reserves, the Board reviewed its data regarding WGML's contractual interests in gas units. The Board found that its estimates of the unit control percentage for WGML were frequently understated. Updated information has been used to develop the Board's estimate of these WGML reserves, and this data is now generally in agreement with that submitted by WGML. Differences in interpretation of WGML's contractual interests remain, however, for a number of non-unitized pools.

In summary, the Board has updated its estimate of WGML's reserves and finds that its estimate is lower than the revised estimates provided by WGML. The discrepancy in estimates of reserves arises primarily from differences in geological and engineering evaluations of specific pools but is also due to differences in interpretation of WGML's contracted lands position and the approach to pool coalescence adopted by WGML. The Board is cognizant of the difficulty in maintaining reliable current estimates of reserves for the large number of pools in WGML's supply portfolio and is aware that legitimate differences in technical evaluations arise due to the interpretative nature of reserves analysis. For these reasons, the Board will continue to review its reserves data on an ongoing basis in an effort to further identify and assess the noted differences.

A further issue relevant to consideration of WGML's gas supply is the extent to which its producers are contractually committed to WGML in the longer term. WGML submitted evidence in this regard during the proceeding.

WGML's gas supply is contracted from approximately 750 producers and suppliers. The 30 November 1988 netback agreement between WGML and its producers established new termination dates for all of WGML's producer contracts by extending them to the economic life of the reserves. The agreement has been accepted by producers representing 99 percent of WGML's contracted supply and provides producers with three options related to their contracts with WGML. The options available to the producer are as follows:

(a) do nothing, in which case the contracts remain as amended by the netback agreement and are extended to the economic life of the reserves under contract;

(b) exercise the volume reduction option, which gives the producer, in the years following 1994, the opportunity to reduce contract volumes in a following year if a performance level of 75 percent rate-of-take is not achieved by TransCanada; and/or

(c) exercise the option to re-establish the initial contract termination date by serving notice four years prior to such date, to be effective after the 1993/94 contract year.

The specifics of each of these options are discussed below.

• Do Nothing Option

A producer can maintain the status quo under a contract and let it run to the end of the economic life of the reserves. WGML will continue to purchase and market the producer's gas under the terms of the agreement.

• Volume Reduction Option

If the rate-of-take from all of a producer's contracts is less than 75 percent in any contract year commencing on or after 1 November 1993, a producer may subsequently elect to reduce its volume obligation to WGML according to a formula in the agreement. The volume obligation may be reduced in any one or more of the following ways, provided that all TopGas advances have been recovered:

(i) by terminating a contract (if one exists at an appropriate volume);

(ii) by reducing the reserves under contract through the deletion of a portion of the lands dedicated to the contract; and/or

(iii) by reducing the allocation reference quantity [1] in effect under a contract, which provides the producer the right to sell gas produced from the contract lands in excess of the maximum daily quantity.

For each of the above methods, the rate-of-take from all of a producer's contracts would be the lower limit of the extent to which volume reduction can be implemented. The volume reduction option has the practical effect of allowing producers the flexibility to remove from WGML's supply base a portion of the supply between the producer's rate-of-take level and the 75 percent level.

• Termination Option

The termination option in the netback agreement gives a producer the right to terminate a contract with WGML by serving notice four years in advance. The earliest date that a contract can be terminated is 1 November 1994, and producers wishing to pursue this option were to notify WGML by 4 January 1991. This option is subject to there being no outstanding TopGas advances to the producer or any other party to the contract.

WGML indicated that contracts representing some 85 percent of its year-end 1989 total remaining reserves are eligible for contract termination between 1994 and 2005. The largest block of contracts, or annual volume, is eligible for termination effective 1 November 1994. WGML estimated that this block would represent about 30 percent of its remaining reserves at that time. Additionally, this volume is significantly larger than the annual volumes eligible for contract termination in other years and exceeds the total volume eligible for termination between 1995 and 2005.

1. The allocation reference quantity established by the netback agreement is the minimum day quantity of the original contract multiplied by 365.

WGML estimated during the early stages of this proceeding that producers representing less than five percent of its total remaining reserves on 31 October 1994 would exercise the termination option. This estimate was predicated on the belief that producers would opt for the volume reduction option. WGML was of the view that producers might not be able to project beyond the required four-year notice period and that this time period would effectively act as a deterrent to contract termination. WGML also believed that the joint venture nature of the producing industry would deter producers from exercising the termination option because unanimity among partners would be required for multi-party contracts.

As this proceeding progressed, WGML revised its estimate of terminations to between seven and ten percent of its total remaining reserves as of 31 October 1994. This amount is equivalent to approximately one-third of the gas supply which is eligible for contract termination.

The deadline for notification by producers intending to terminate contracts with WGML effective 1 November 1994 was extended from 1 November 1990 to 4 January 1991. WGML subsequently indicated that it had received termination notices from producers for approximately 14 percent of its total remaining reserves as of 31 October 1994. Thus, about one-half of the supply eligible for contract termination in November 1994 will be removed from WGML's gas supply portfolio via this option. Although producers' reasons for terminating their contracts are varied, WGML cited current low rates-of-take under particular contracts and consolidation of highly fractioned working interests through property acquisition as reasons why the level of contract termination was higher than it had previously expected.

In addition to extending the deadline for termination notices to 4 January 1991, WGML offered producers the option to roll-over the four-year notice period for eligible contracts for one year, so that notices on those contracts could be given 1 November 1991 for termination on 31 October 1995. Initially, a maximum of 0.5 Tcf of remaining reserves was eligible for termination on 31 October 1995; that eligible volume will now be approximately 2 Tcf. WGML indicated that termination of approximately 0.7 Tcf on 31 October 1995 was expected.

At the request of the Board, WGML presented a "worst case" scenario for contract termination which assumed that all producers would terminate their contracts at the earliest possible time. This case, which assumes that production continues at capacity and historical reserves development on contract lands continues, is presented in Figure 17.1 along with the cumulative eligible volume and the actual termination expected for the 1994/1995 contract year. The cumulative volume eligible for contract termination in 1994 includes the roll-over of terminations discussed above. Volumes included under contracts which have not been terminated by producers may be carried forward and thereby are eligible for contract termination in 1995 and subsequent years. It should be noted that the worst case scenario does not include volumes which may be removed from the WGML supply pool by producers under the volume reduction option.

WGML received more notification of contract terminations effective 1 November 1994 than it had anticipated. However, it expects that the level of future terminations will be reduced considerably because higher rates-of-take under its producer contracts will be achieved through increased market requirements and declining supply capability. In fact, for these reasons WGML projects that its average rate-of-take for producers' contracts will be above 75 percent when the reduction entitlement becomes effective in the 1994/1995 contract year. Therefore, WGML does not anticipate any significant reduction of supply volume under this option. WGML further submitted that if partial decontracting options are available because the rate-of-take does not rise as expected, then the volume reduction option will have the desired result of bringing supply and requirements into line.

The extent to which the contract termination options in WGML's producer contracts are exercised may have implications for WGML's ability to contract new sales. WGML stated that as licences for renewed volumes become necessary, it will have to seek Board approval; however, its contractual provisions preclude it from making new commitments or renewing existing contracts if its RR/P ratio falls below ten. Assuming that production equals total contracted requirements, both WGML's and the Board's preliminary estimates indicate that, after allowance for those contract terminations effective 1 November 1994, the RR/P ratio for any year of the projection period would not fall below ten.

17.2.2 Productive Capacity

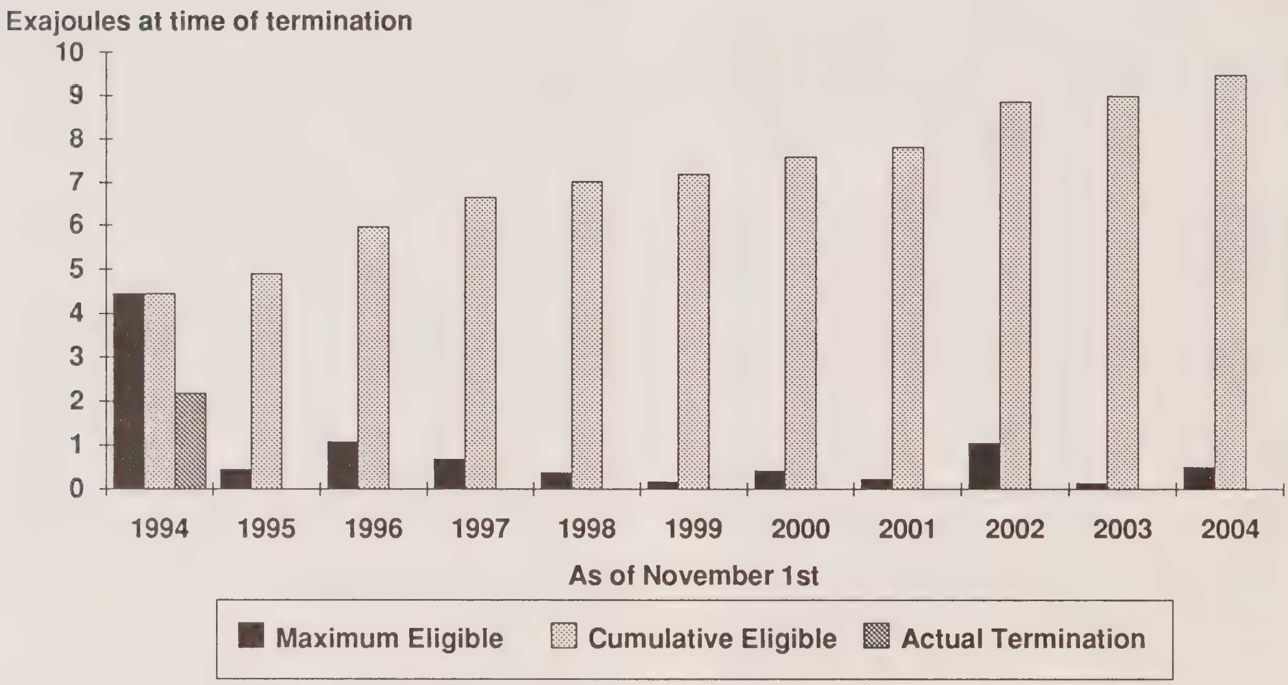
In order to assess the adequacy of WGML's gas supply, it is necessary to compare projections of productive capacity relative to requirements under various scenarios. These scenarios relate to the extent to which contract termination by WGML's producers may occur and the requirements outlook which is anticipated for WGML.

In all cases, both WGML's and the Board's projections of productive capacity have been adjusted to reflect production at the projected level of requirements. As well, projections of productive capacity reflecting contract terminations effective 1 November 1994 and maximum possible contract terminations have been adjusted consistent with the methodology used by WGML. Productive capacity was reduced in the years following 1 November 1994 by percentages indicative of the amount of reserves lost due to contract termination. This methodology is somewhat conservative, in that the majority of the terminating contracts will have produced for well in excess of 20 years at the time of termination and would be generally at a higher rate of decline than the supply as a whole. This causes the methodology to show a greater impact on the total productive capacity in the remainder of the projection period than may actually materialize.

Two demand scenarios were examined. The first provides for the evergreening of both WGML's export and domestic requirements. It can be characterized as WGML's expected level of requirements if gas were to continue to flow to its traditional domestic and export markets. The second demand scenario examines only WGML's contracted domestic and export requirements, or simply its non-evergreened requirements. This is the level of demand to which WGML is currently contractually committed. Included in the early years of both requirements scenarios are WGML's estimates of excess gas sales to non-WGML markets from its contracted pools.

Figure 17.1

Estimated Remaining Reserves Eligible for Termination



Three supply scenarios were developed to compare to these requirements scenarios. Both Board and WGML estimates of WGML's productive capacity were examined. WGML's projections include its estimates of productive capacity from reserves growth on contracted lands, whereas the Board projections represent productive capacity from established reserves only. Both the inclusion of reserves growth by WGML and the fact that the Board's estimates of established reserves are less than WGML's tend to make WGML's projections more optimistic than the Board's, particularly later in the projection period.

The first supply scenario represents productive capacity from all remaining reserves under contract to WGML as of 31 October 1988, without any contract termination. The second supply scenario illustrates the effect of maximum contract termination. This scenario does not, however, reflect the volume reduction option in addition to the eligible volume for contract termination. The third supply scenario reflects the known contract termination notices effective 1 November 1994, but assumes that no further contract terminations occur. We would expect that WGML's future productive capacity would fall within the band between scenarios two and three, all other things being equal. As noted earlier, WGML does not expect future terminations to be very significant because higher rates-of-take under its producer contracts will be achieved through increased market requirements and declining supply capability.

WGML's evergreened domestic and export requirements are compared to all three WGML and Board supply scenarios in Figures 17.2 and 17.3, respectively.

Assuming no contract termination, Figure 17.2 illustrates that WGML's estimates of productive capacity suggest that it would be able to meet fully evergreened requirements up to and including 1998, whereas Figure 17.3 demonstrates that the Board's estimates suggest that WGML could meet its fully evergreened requirements up to and including 1997. Although the Board's estimate of reserves is significantly less than WGML's, the Board believes that a higher rate-of-take than that used by WGML is feasible. This results in the Board's projection of productive capacity being higher initially, and lower towards the end of the term of the proposed licences, than WGML's projection. This is further influenced by WGML's inclusion of reserves growth on its contracted lands, while the Board's projection reflects only established reserves.

Assuming maximum contract termination, both WGML's and the Board's estimates of productive capacity, shown in Figures 17.2 and 17.3 respectively, suggest shortfalls from 1995 onwards. However, this presentation does not include any loss of gas supply which may occur through the volume reduction option.

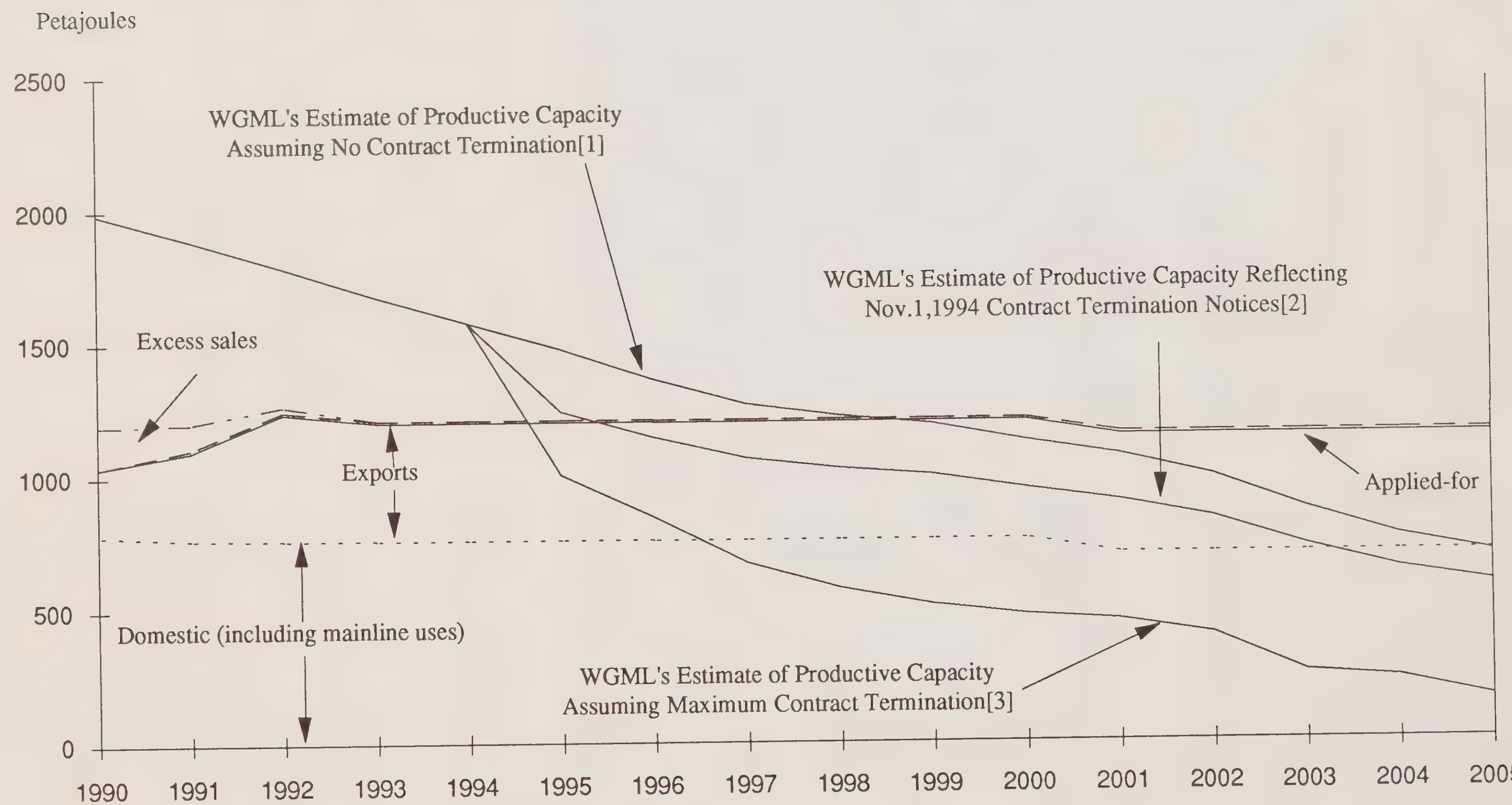
Both WGML's and the Board's estimates of productive capacity reflecting 1 November 1994 contract terminations indicate shortfalls commencing in 1996, but the projected shortfalls are much less than those indicated for the maximum contract termination scenario.

Figure 17.4 provides a comparison of WGML and Board estimates of productive capacity to non-evergreened domestic and export requirements, or WGML's current and proposed contractual commitments. Both WGML's and the Board's estimates of productive capacity reflecting the 1 November 1994 contract termination indicate that WGML would be able to meet its contractual commitments throughout the term of the proposed export licences. Figure 17.4 also compares WGML's and the Board's productive capacity projections assuming maximum contract termination. Under this supply scenario, both WGML's and the Board's projections suggest that contracted requirements could not be met from 1999 to 2003.

While WGML expects to service the volumes included in the evergreened case, it indicated that, with respect to project-specific supply, it is bound to serve only its contracted requirements. WGML emphasized that no party at the proceeding substantially challenged its assertion that it had enough gas to meet its contracted requirements, and assured the Board that it will be able to manage its supply in order to meet future requirements.

Figure 17.2

COMPARISON OF WGML'S ESTIMATES OF ANNUAL PRODUCTIVE CAPACITY TO WGML'S EVERGREENED DOMESTIC & EXPORT REQUIREMENTS



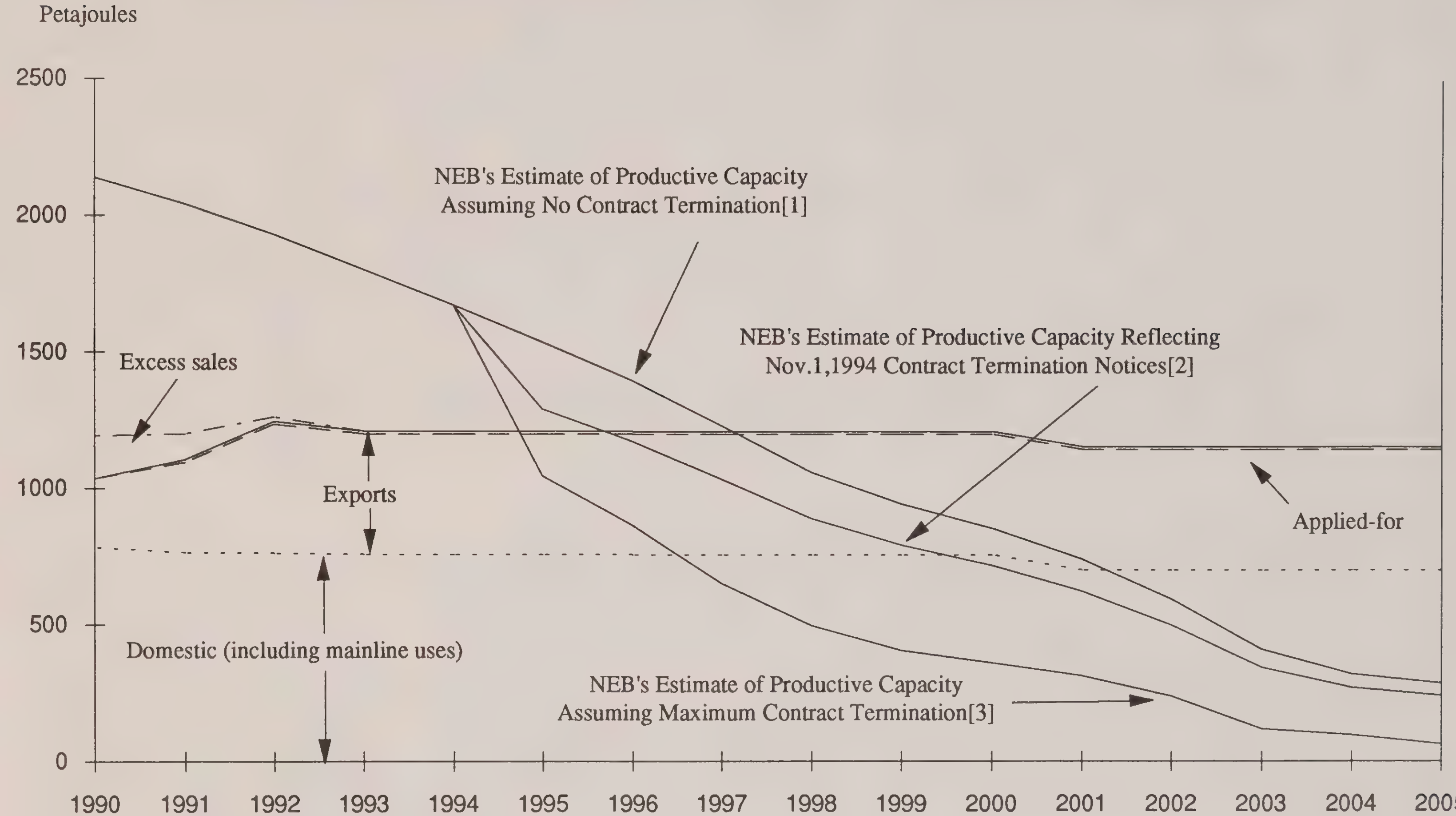
1. WGML's estimate of productive capacity assuming that no contract terminations occur over the projection period.

2. WGML's estimate of productive capacity reflecting termination notices received to date and effective in the 1994/95 contract year. No contract terminations beyond the 1994/95 contract year are reflected in this projection.

3. WGML's estimate of productive capacity assuming the maximum possible number of producers exercise their options related to contract termination at the earliest possible dates over the projection period.

Figure 17.3

COMPARISON OF NEB's ESTIMATES OF ANNUAL PRODUCTIVE CAPACITY TO WGML's EVERGREENED DOMESTIC & EXPORT REQUIREMENTS



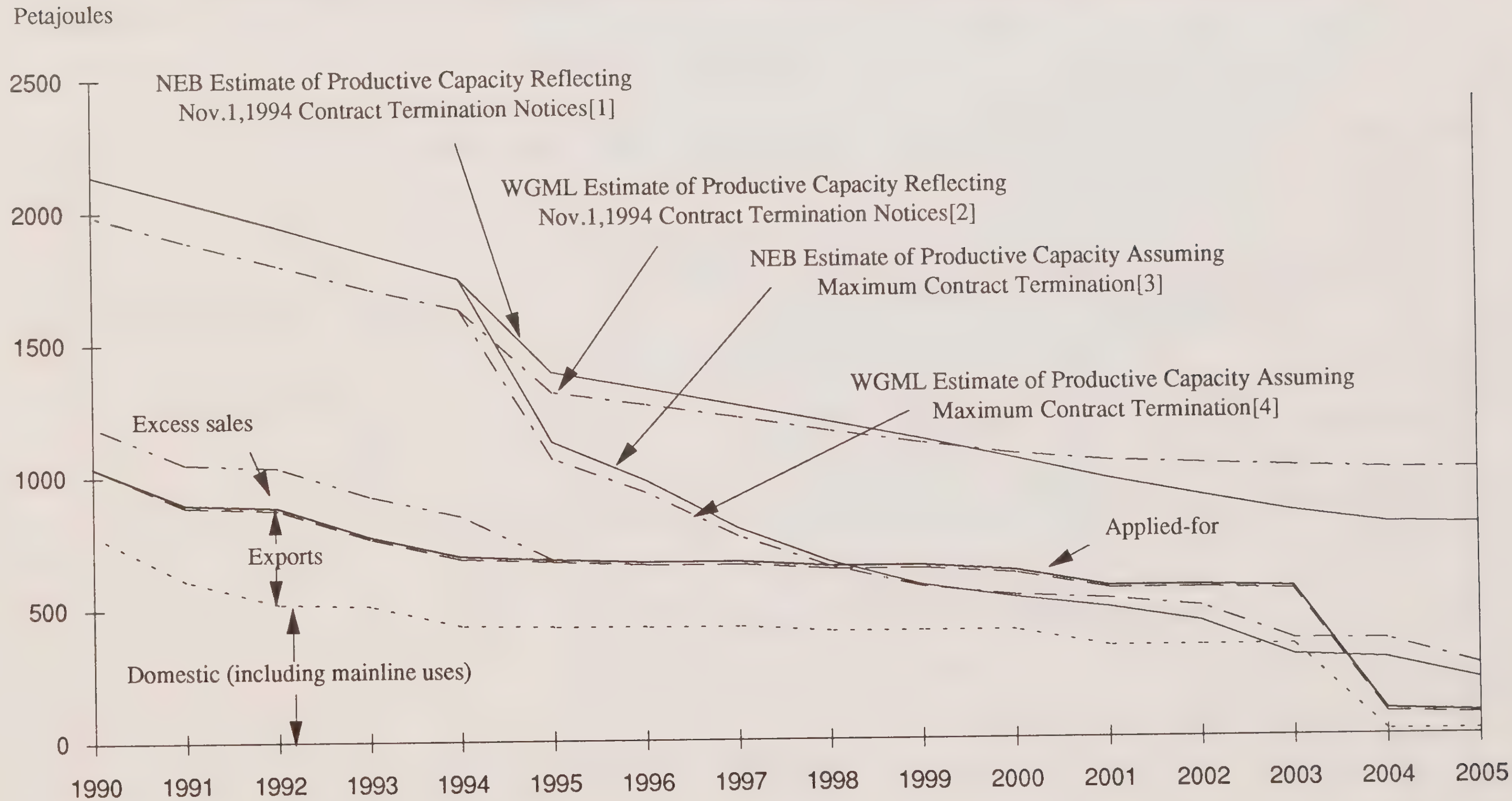
1. NEB's estimate of productive capacity assuming that no contract terminations occur over the projection period.

2. NEB's estimate of productive capacity reflecting termination notices received to date and effective in the 1994/95 contract year. No contract terminations beyond the 1994/95 contract year are reflected in this projection.

3. NEB's estimate of productive capacity assuming the maximum possible number of producers exercise their options related to contract termination at the earliest possible dates over the projection period.

Figure 17.4

COMPARISON OF NEB's & WGML's ESTIMATES OF ANNUAL PRODUCTIVE CAPACITY TO WGML's NON-EVERGREENED DOMESTIC & EXPORT REQUIREMENTS



1. NEB's estimate of productive capacity reflecting termination notices received to date and effective in the 1994/95 contract year. No contract terminations beyond the 1994/95 contract year are reflected in this projection.

2. WGML's estimate of productive capacity reflecting termination notices received to date and effective in the 1994/95 contract year. No contract terminations beyond the 1994/95 contract year are reflected in this projection.

3. NEB's estimate of productive capacity assuming the maximum possible number of producers exercise their options related to contract termination at the earliest possible dates over the projection period.

4. WGML's estimate of productive capacity assuming the maximum possible number of producers exercise their options related to contract termination at the earliest possible dates over the projection period.

17.3 Market and Commercial Arrangements and Regulatory Status

17.3.1 Market

Elizabethtown is an LDC serving nearly 220,000 customers in central and northwestern New Jersey. The company, established in 1855, is New Jersey's oldest all-gas utility. Elizabethtown's markets consist of residential buyers, commercial accounts, firm and interruptible industrial users and cogeneration customers. Jersey Central Power and Light ("JCP&L"), representing approximately 16 percent of Elizabethtown's sales, is its largest account, purchasing gas on an interruptible basis for the generation of electricity. WGML stated that, on a 100 percent load factor basis, Elizabethtown expects that up to 40 percent of the export volume could be sold to JCP&L. Elizabethtown also transports third-party gas.

Elizabethtown provided a forecast of its gas sales for the next eight years, indicating an overall growth rate of 2.4 percent per annum. From a sales level of approximately 1 614 10^6m^3 (57 Bcf) in 1989, the company projects a rise to about 1 956 10^6m^3 (68 Bcf) in 1997. The major areas of growth are expected to be in power generation, including cogeneration, and in the residential and commercial markets. In particular, Elizabethtown has been reviewing the potential for cogeneration development in its territory, noting that several large-scale projects have been proposed. WGML stated, however, that Elizabethtown anticipates using the export volumes for general system supply and has not dedicated the gas to cogeneration markets.

In recent years, Elizabethtown has been diversifying its gas supply portfolio. For example, the company has contracted for Appalachian area gas supplies which have been dedicated to two cogeneration customers. According to WGML, the acquisition of Canadian gas would represent one part of Elizabethtown's program of gas supply diversification. After considering purchase obligations and related monetary and volumetric reduction penalties under its supply contracts, Elizabethtown forecasts an average load factor under this contract in excess of 90 percent. Actual purchases could be affected by the price of the supplies, the price of alternate supplies, unanticipated growth in Elizabethtown's markets and subscription to additional storage services. The pricing terms of the agreement between Elizabethtown and WGML were designed, in part, to make the Canadian supply an attractive energy source for JCP&L in the summer, to encourage a high load factor. Elizabethtown has stated that its gas supply portfolio is subject to annual review by the New Jersey Board of Public Utilities in its annual levelized purchase gas cost proceeding.

Elizabethtown has significantly decreased its reliance on its largest traditional supplier, Transco, converting nearly one-half of its full service contract to firm transportation only and negotiating alternative gas purchase arrangements. The company's other principal suppliers include Tetco, National Fuel, Tennessee, CNG and Columbia. Elizabethtown does not expect to release any rights under its contracts with existing suppliers in order to obtain the new supply from WGML. The Canadian gas, which, according to WGML, would represent some ten percent of Elizabethtown's total annual supply, would be accommodated by the growth in the company's markets as well as by the flexibility included in Elizabethtown's current contracts.

17.3.2 Transportation

The proposed export volumes would be transported to Empress, Alberta on the NOVA system. From Empress, it would be delivered by TransCanada to the international border at Niagara Falls, Ontario. From the border, the gas would be delivered to Elizabethtown through arrangements with Tennessee, National Fuel and Transco.

Within Alberta, the gas would be transported to Empress under an existing agreement between NOVA and TransCanada. According to WGML, it is not expected that incremental capacity would have to be built for this sale or that TransCanada would be required to contract for additional NOVA capacity. WGML has executed a precedent agreement with TransCanada to transport the gas from Empress to Niagara Falls. These volumes are included in TransCanada's queue for firm service commencing 1 November 1991. The facilities required to transport the Elizabethtown

volumes are included in TransCanada's GH-5-89 facilities application.

On the U.S. side, Elizabethtown has executed a precedent agreement with Transco for the transportation of the gas from the international border to its city gate. Tennessee would receive the gas at the international border and transport it on behalf of Transco to the interconnect with National Fuel. National Fuel would, in turn, transport the gas on behalf of Transco to the interconnect with Transco at Leidy, Pennsylvania. Transco would then deliver the gas to Elizabethtown.

Tennessee, National Fuel and Transco applied to the FERC in January 1989 to expand their facilities as part of what is known as the Niagara Import Point System Projects ("NIPS"). On 13 September 1990, the FERC approved the final phase of NIPS, which, among other facilities, authorized Tennessee, National Fuel and Transco to construct and operate the facilities necessary to transport the gas to Elizabethtown's city gate.

17.3.3 Gas Sales Contract

WGML filed a copy of its precedent agreement with Elizabethtown dated 30 October 1989, attaching a pro forma gas sales contract that would be signed when all of the conditions precedent have been satisfied. In the precedent agreement, conditions include the requirements that buyer and seller obtain the necessary regulatory import and export authorizations and arrange for transportation. All approvals must be received by 1 January 1992, otherwise the agreement may be terminated by either party by giving 90 days written notice. There was also a condition that, if the Board orders an incremental demand or commodity charge in respect of pressure at Niagara Falls, then, within 45 days of the issuance of the order, WGML and Elizabethtown would negotiate an amendment to ensure that any pressure charge at Niagara Falls would be passed through to Elizabethtown. Subsequent to the execution of the precedent agreement and certain decisions and orders of the Board, WGML and Elizabethtown signed an agreement on 4 April 1990 amending the gas sales contract to provide for the inclusion of the Niagara Falls pressure charge in the contract and the terms of payment.

The gas sales contract would extend for a term of 15 years from the date of first deliveries and would continue beyond that period as long as the regulatory authorizations are in place unless either party gives 12 months written notice. The DCQ is 283 10^3m^3 (10 MMcf) and the ACQ is 104 10^6m^3 (3.7 Bcf). Elizabethtown is required to take at least 60 percent of the ACQ or make up the deficient volume in the next contract year. In the event that it is not made up, WGML has the right to permanently reduce the DCQ by the deficient volume. The contract allows Elizabethtown to increase the DCQ by up to 142 10^3m^3 (5.0 MMcf), subject to regulatory approvals.

The contract includes a provision whereby WGML's supplier, TransCanada, agrees to maintain an RR/P above a factor of ten, calculated for selected periods. TransCanada and WGML are not permitted to enter into new sales arrangements if the RR/P is below ten or if the new agreements could cause the RR/P to fall below ten. As well, if at any time the total supply of gas was insufficient to meet commitments, TransCanada would first curtail short-term sales and then, if necessary, prorate long-term sales.

The contract includes a three-part pricing structure consisting of a demand charge, a delivery pressure charge and a commodity charge.

The demand charge component consists of the monthly demand toll on TransCanada and the average monthly demand toll on NOVA together with a fixed monthly administrative charge of \$ U.S. 4.56 per Mcf of DCQ. Elizabethtown's minimum bill for each month would be the monthly demand charge.

The delivery pressure charge is equal to the charge for transportation on TransCanada as approved by the Board for deliveries at pressures in excess of 4 000 kilopascals at Niagara Falls. The charge includes the monthly demand and commodity components of the delivery pressure toll and the cost of compressor fuel required to elevate the pressure.

The commodity charge is determined by subtracting the demand charge from an adjusted base price ("ABP"). For the winter period, November through March, the ABP consists of a

winter base price ("WBP"), set initially at a level of $ U.S. 2.90/GJ ($ U.S. 3.06/MMBtu). The WBP is adjusted monthly by an index reflecting a rolling twelve-month average of the prices of Elizabethtown's other purchases of gas under contracts for firm delivery for at least 152 days of the year, with terms of three years or more. For the first 30 percent of the DCQ volumes purchased in the summer, April through October, the ABP consists of a summer base price ("SBP"), established initially at $ U.S. 2.37/GJ ($ U.S. 2.50/MMBtu). The SBP is adjusted monthly by an index reflecting a rolling 12-month average of the prices of all of Elizabethtown's other gas purchases, both firm and interruptible.

An incentive commodity charge ("ICC") is applied to volumes purchased in the summer in excess of 30 percent of the DCQ which is equal to the lesser of the prices of No. 6 fuel oil (one percent sulphur) and spot gas in Elizabethtown's market area netted back to Niagara Falls. The purpose of the ICC is to provide an economically seasonal price to JCP&L, to stimulate a high load factor. In this connection, WGML said that it expects to operate the contract at an average load factor in excess of 90 percent.

WGML provided information to illustrate how the contract prices would have been calculated for selected months in 1989. In July, for example, the commodity charge at 100 per cent load factor would have been $ U.S. 1.62/GJ ($ U.S. 1.71/MMBtu) and, in December 1989, it would have been $ U.S. 2.12/GJ ($ U.S. 2.24/MMBtu).

The estimated price at the Alberta border as of January 1990 under this contract was $ Cdn. 2.09/GJ ($ Cdn.2.24 /MMBtu).

Each year, under the terms of the contract, either party is permitted to seek a renegotiation of the pricing provisions. While the use of the demand/commodity charge structure is subject to renegotiation, if a demand charge is retained, the NOVA and TransCanada components would be maintained and are not subject to renegotiation. In the event that the demand charge was removed, WGML stated that it would be committed to pay the demand charge component. If agreement is not reached, binding arbitration is invoked. The purpose of arbitration would be to determine whether adjustments to the pricing provisions were required, within the general framework that the gas should be competitive with the prices of major competing energy sources in the markets served by Elizabethtown. As well, the price of the gas should be comparable with the prices of other long-term, firm Alberta gas supplies sold by WGML to other customers in the northeastern U.S. under similar terms and conditions

17.3.4 Regulatory Status

WGML would remove the Elizabethtown volumes utilizing the existing AERCB removal permit TC-85-1 which was granted 3 January 1986 and expires 31 October 1999. WGML would have to apply to extend this permit in the future. WGML indicated that the application was in the latter planning stages but that a target date for its submission had not been set.

In September 1990, Elizabethtown received DOE/FE import authorization.

17.4 Views of Intervenors

Union indicated that it does not consider the maximum contract termination case to be WGML's "worst case" supply scenario, in that producers may also exercise the volume reduction option to reduce their commitments to WGML. Union argued that if rates-of-take are low and producers elect to reduce their commitments to the maximum, then virtually all of WGML's supplies would disappear within a few years of 1994. While Union recognized that WGML had testified that it was unlikely that all of the producers would exercise their contractual rights, Union submitted that the Board should be mindful of the difficulty WGML has had in accurately predicting the behaviour of its suppliers.

Union's views with respect to WGML's supply are discussed further in chapter 19 of these Reasons in the context of the overall supply available to the proposed facilities.

The Independent Petroleum Association of Canada ("IPAC") stated that in its view WGML had ample gas to meet its contracted volumes.

The Alberta Petroleum Marketing Commission ("APMC") indicated that the Board should assess the ability of WGML to meet its current contracted requirements for their full terms.

TransCanada stated that it believed the Board should approve the WGML licence application.

Union requested that the Board deny WGML's application on the grounds that there is no provision in the contract which obliges Elizabethtown to take the contracted volumes. Union stated that there are two principal methods of providing assurance of take. The first is a minimum volume obligation such as a take-or-pay provision and the second is a provision prohibiting the acquisition of gas for the project from any alternate source. Union expressed the opinion that demand charge obligations alone do not constitute reasonable assurance that the gas would be taken.

WGML argued that the estimated load factor under this contract was 90 percent. This estimate was based on Elizabethtown's view of dispatchability of gas supplies and on the fact that WGML is high on Elizabethtown's supply queue because of the contract's market-based pricing mechanism. WGML stated that high takes are assured in this particular sale, not because of a take-or-pay provision, but as a result of the market-responsive nature of the pricing structure, including the seasonal adjustment provision.

17.5 Views of the Board

The Board reviewed WGML's estimates of TransCanada's reserves and productive capacity and compared these with its own.

The Board's estimate of reserves is about 20 percent lower than WGML's estimate. The difference in estimates of reserves arises primarily from differences in geological and engineering evaluations of specific pools, but also from differences in the interpretation of WGML's contracted lands position.

The Board assessed WGML's productive capacity relative to requirements under a number of scenarios. The Board notes that if new exports are imposed on a base demand that assumes evergreening of both existing domestic and export sales, productive capacity estimates by both WGML and the Board fall below requirements by 1995 under WGML's "worst case" maximum contract termination scenario (Figures 17.2 and 17.3). The shortfall in productive capacity occurs later in the term of the proposed export if it is assumed that fewer contract terminations occur. However, the WGML Elizabethtown application is relatively small as compared to WGML's overall requirements, and both WGML's and the Board's estimates of productive capacity suggest that sufficient supply exists to satisfy WGML's current contractual commitments, including the proposed export, even if a significant ongoing level of contract terminations or volume reductions is assumed (Figure 17.4).

The Board agrees with WGML that the contract termination and volume reduction options available to producers would, to the extent they are exercised, jointly have the effect of improving the overall supply/demand balance for WGML. Contract terminations should increase the overall rate-of-take to a level which would prevent producers from exercising the full volume reduction option. To the extent that contract terminations do not occur, and the rate-of-take remains low, then producers would have the opportunity to exercise the volume reduction option. Both should have the effect of improving WGML's overall supply and demand position. Therefore, the Board believes that it is unlikely for a situation to occur in which both the contract termination and volume reduction options would be fully exercised. For that reason, the Board considers Union's position, that is that WGML's maximum termination case is not a "worst case" scenario, to be an unduly pessimistic assessment of WGML's future supply capability. The Board also notes that contractual provisions preclude WGML from entering into new sales arrangements or renewal of existing arrangements if its RR/P ratio falls below ten and that future export applications are subject to the scrutiny of the Board.

The Board believes that the appropriate approach to assessing the adequacy of WGML's supply is to compare WGML's available contracted supply to its current contractual commitments and notes that the evidence in the proceeding suggests that supply would be adequate even if a significant ongoing level of contract termination or volume reductions is assumed. Accordingly, the Board is

satisfied that WGML has adequate gas supply to meet its currently contracted domestic and export sales requirements, including the proposed Elizabethtown export.

The Board is satisfied that WGML has adequately demonstrated that the Elizabethtown market represents a stable, long-term market for Canadian gas. The Board notes that this supply represents approximately 10 percent of the LDC's annual requirements and that, in 1988, residential customers accounted for 34 percent and public utilities for 22 percent of Elizabethtown's total throughput.

The WGML/Elizabethtown contract includes provisions which provide for complete recovery of NOVA and TransCanada demand charges including any pressure charges associated with delivery at Niagara Falls. The Board is satisfied that the contract would ensure the recovery of all fixed Canadian transportation costs.

The Board has reviewed the commodity pricing formula in the contract. The Board notes that it is designed to track the prices of other gas supplies available to Elizabethtown and that it includes incentive pricing in the summer months to encourage JCP&L, the LDC's largest account, to take the gas during that period. The contract provides for annual renegotiation of the pricing provisions and arbitration if necessary. The Board is of the view that the contract is so structured as to permit adjustments to reflect changing market conditions over the life of the contract.

The Board disagrees with Union's argument that the contract does not contain a provision which obliges Elizabethtown to actually purchase any of the export volumes applied for. The gas purchase contract includes a minimum take provision whereby WGML can elect to reduce the DCQ if Elizabethtown fails to take 60 percent in one year and fails to make up the deficient volume in the next. The demand component of the pricing structure ensures payment of transportation demand charges and also includes a fixed monthly administration fee whether or not the gas is taken. The commodity pricing formula, in addition to being market responsive, is seasonally adjusted to encourage JCP&L, Elizabethtown's largest account, to take the gas during the summer months. In the Board's opinion, the above described provisions, when taken as a whole, offer reasonable assurance that the contracted volumes would be taken. The Board is satisfied that the gas sales contract has been negotiated at arm's length between WGML and Elizabethtown.

With regard to a prohibition against displacement clause, the Board notes that while Union may feel that it is a desirable provision, it is not one which is widely in use and, in the Board's view, the lack of such a clause does not constitute grounds for denying an application. The Board also notes in this regard that producer support for the contract was received.

17.6 Decision

The Board has decided to issue a gas export licence to WGML, subject to the approval of the Governor in Council. Appendix IV contains the terms and conditions of the licence, including a condition that the term of the licence shall commence on the date of first deliveries and shall end on 1 November 1993, unless exports have commenced under the licence on or before 1 November 1993, in which case the term would end 15 years following the date of first deliveries.

PART III MATTERS

Chapter 18
TransCanada's Facilities Application

Chapters 18 to 25 of these Reasons deal with TransCanada's application dated 29 June 1989, as amended 15 December 1989, for a certificate of public convenience and necessity in respect of its proposed 1991 and 1992 facilities, as well as for certain exemptions pursuant to section 58 of the Act from the provisions of subsections 31(c) and 31(d) and section 33.

A description and the estimated capital cost of the facilities addressed in this final phase of the proceedings are provided in Table 22-1. A map indicating the location of these facilities appears as Figure 22.1. Specific facilities that have been certificated as a result of the Board's decision outlined in Volume 2 of these reasons, or exempted from certification pursuant to section 58 of the Act prior to the release of Volume III of these Reasons, are identified in Appendix V.

Chapters 19, 20 and 21 address the supply, market and contractual aspects of the evidence and argument submitted in the proceedings. In arriving at its findings on these matters, the Board relied on TransCanada's evidence as well as on the evidence related to specific service requests adduced by the Part VI applicants in the GH-5-89 proceedings. As indicated in Chapter 1 of these Reasons, notwithstanding the fact that common information was used in support of Part VI applications and TransCanada's facilities application, the Board's decisions on these applications were arrived at independently.

Chapters 22 and 23 address the design of the proposed facilities, and the associated land use and environmental considerations.

The economic feasibility of the expansion was assessed in accordance with the approach outlined in Chapter 3 of Volume 1 of the Reasons for Decision in these proceedings, issued November 1990. The Board's views regarding the economic feasibility of the expansion are found in Chapter 24.

The Board's overall findings regarding the present and future public convenience and necessity of the proposed facilities, as well as the Board's decisions in respect of TransCanada's applications pursuant to sections 52 and 58 of the Act, are found in Chapter 25.

Chapter 19
Supply Matters

In considering TransCanada's application, the Board examined two aspects of supply:

- project-specific supply (discussed in subsections 19.1); and
- overall supply (addressed in section 19.2).

Project-specific supply refers to the supply in respect of new requests for service associated with the proposed expansion. In this regard, the Board examined whether each shipper had secured or would secure adequate supply to meet its obligations.

Overall supply refers to the total supply of natural gas that will be available to the TransCanada system as well as to other Canadian pipeline systems. In this respect, the Board considered whether there would be adequate gas supply to ensure sufficient utilization of the total TransCanada pipeline capacity in the long term and to ensure the financial viability of the pipeline.

19.1 Project - Specific Supply

As shown in Table 20-6, there are three distinct types of FS requirements supporting TransCanada's proposed facilities:

(i) new exports (already licensed);

(ii) new exports (licences considered in the GH-5-89 proceeding);and

(iii) new domestic services.

With respect to the first category, the Board did not consider it necessary to re-examine project-specific supply during the GH-5-89 hearing. Those projects for which licences have already been issued are the Alberta Northeast Gas Export Project ("ANE") exporters, Shell/Granite State and FSC/Plattsburg.

The supply for new exports (category 2) was considered during the proceeding and the Board's findings, which are equally applicable for Part VI and Part III purposes, are provided in Chapters 3 through 17 of these Reasons. This category includes the ProGas application which was for a change to an existing service that resulted from the modification of an existing export licence.

The project-specific supply in respect of new domestic services (category 3) was addressed in the Reasons for Decision, Volume 2 - Partial Facilities.

19.2 Overall Gas Supply

In the GHW-3-89 proceeding, the Board reaffirmed the role of overall supply analysis in determining whether pipeline facilities such as those proposed in the TransCanada application are and will be in the present and future public convenience and necessity. The Board noted that an overall supply assessment provides an indication as to the supply available to keep existing pipeline capacity utilized and is also a consideration in assessing the economic feasibility of a facilities expansion, given that the terms of the underlying contracts are often for shorter periods than the economic life of new facilities. The Board directed that:

> *"TransCanada shall provide evidence that it has assured itself that there is, or will be, adequate natural gas supply to ensure sufficient utilization of its total pipeline capacity in the long-term, taking into consideration all potential supply sources that could reasonably be expected to be connected to the TransCanada system and the domestic and export demand for Canadian gas that could reasonably be expected to be served via the TransCanada system."*

The Board, in its Reasons for Decision on Tolling and Economic Feasibility (Volume 1 of the Reasons for Decision in these proceedings), stated

that a determination of the economic feasibility of the proposed GH-5-89 pipeline facilities was most appropriately made through a determination of the likelihood of the facilities being used at a reasonable level over their economic life and a determination of the likelihood of the demand charges being paid. One of the factors which was identified as providing an indication of whether this was likely to occur was "evidence that there is likely to be a sufficient long-term supply of gas to keep the pipeline fully utilized over its economic life".

This section will address the overall supply evidence submitted by TransCanada and its relevance to the facilities application. It will also address the impact of contract terminations by WGML's producers on TransCanada's overall supply situation and on the Board's assessment of the economic feasibility of the proposed expansion (for further details on contract terminations see section 17.3 of these Reasons).

To demonstrate the adequacy of overall gas supply, TransCanada relied upon a study of the future natural gas supply capability of the Western Canadian Sedimentary Basin ("WCSB") by Sproule Associates Limited ("Sproule"). The objective of this study, which was entitled "The Future Natural Gas Supply Capability of the WCSB", was to forecast the natural gas supply that could be expected from the conventional producing areas of the WCSB over the next 20 years, under stipulated price and demand conditions.

Sproule stated that there are three main factors that influence the future natural gas supply capability of the conventional producing areas located in Western Canada. Two of these three factors, namely the current magnitude of remaining established reserves and the future demand for Western Canadian gas, were not studied in detail by Sproule. The final factor, which is the reserves additions that will result from future exploration and development efforts, was the primary focus of the study.

Sproule's methodology for forecasting future reserves additions primarily involves defining two relationships. The first is a reserves additions equation which relates cumulative natural gas reserves additions to cumulative gas-directed drilling. The second is a drilling activity equation, which relates drilling activity to several factors, including energy prices, market conditions and supply costs.

The Sproule methodology requires exogenous assumptions regarding projections of energy prices and demand. For its analysis in this hearing, Sproule used the oil and natural gas prices from the high and low oil price scenarios of the Board's 1988 Supply/Demand report[1]. To project demand, Sproule assumed that Canadian demand for gas in 1989, 1990, and 1991 would be as projected in the 1989 NGMA report[2] published by the Board. Sproule assumed that domestic gas demand would grow by two percent per year between 1991 and 2005 and by one per cent per year thereafter. Domestic demand was projected to be 2 424 PJ in 1995, 2 676 PJ in 2000 and 3 105 PJ in 2010. Sproule projected export demand for Canadian gas by assuming that all existing, pending, proposed and recently denied[3] export volumes would flow at a 90 percent load factor and be evergreened following their scheduled expiry dates. Gross export demand was therefore projected to be 2 023 PJ in 1995, 2 012 PJ in 2000 and 1 991 PJ in 2010. Sproule also assumed that imports would stay at 100 PJ per year, the level projected by Board staff for 1991 in the NGMA. Lastly, Sproule assumed the same demand level in both the low and high oil price scenarios.

With these demand and energy price assumptions, Sproule projected that gas-directed drilling activity would result in reserves additions of between 3.0 and 3.5 Tcf per year in the low oil price scenario. Reserves additions in the high oil price scenario were up to 0.4 Tcf per year higher than in the low oil price scenario. The gas-intent drilling activity necessary to obtain these additions was projected to increase from about 3.81 million metres (12.5 million feet) in 1989 to 8.32 million metres (27.3 million feet) in 2004. The projected level of gas-intent activity is

1. Canadian Energy Supply and Demand, 1987-2000, National Energy Board, September 1988.

2. Natural Gas Market Assessment, National Energy Board, October 1989.

3. The "recently denied" export volumes refer to those licence applications which were denied by the Board in the GH-1-89 proceeding.

substantially higher than historical levels of gas-intent activity, but less than peak annual total drilling levels recorded in the early 1980's. Allowing for reasonable levels of oil-intent activity, Sproule's projected levels of gas-directed drilling activity imply a sustained level of total drilling activity over the period 1992 to 2010 at levels approximating the peak levels of the early 1980's.

Figure 19.1 shows Sproule's projected level of total productive capacity for natural gas from the WCSB. The total projected productive capacity is comprised of productive capacity from established reserves and from reserves additions. Productive capacity from established reserves was higher in the high price scenario than in the low price scenario because unconnected reserves were connected somewhat faster at higher prices. Productive capacity from reserves additions was also higher in the high price scenario because reserves additions were higher and were connected more quickly than in the low price scenario. This figure also shows Sproule's total demand projection, which is comprised of domestic and export demand as described earlier.

As illustrated in Figure 19.1, productive capacity was sufficient to satisfy the assumed demand level until about 2007 in the low oil price scenario and until approximately 2009 in the high oil price scenario.

Sproule also evaluated the cashflows predicted by the model under the high and low price scenarios and compared the return on capital employed for each price scenario with the petroleum industry's recent performance. On the basis of this comparison, it was concluded by Sproule that the economics inherent in the supply capability model were reasonable.

The Sproule study did not purport to address potential supply sources that could be expected to be connected to the TransCanada system beyond the conventional producing areas of the WCSB. It also did not explicitly consider unconventional supply sources such as tight gas or coalbed methane. TransCanada did not comment on the supply capability likely to be available to the proposed facilities beyond the study period (ie. post 2011).

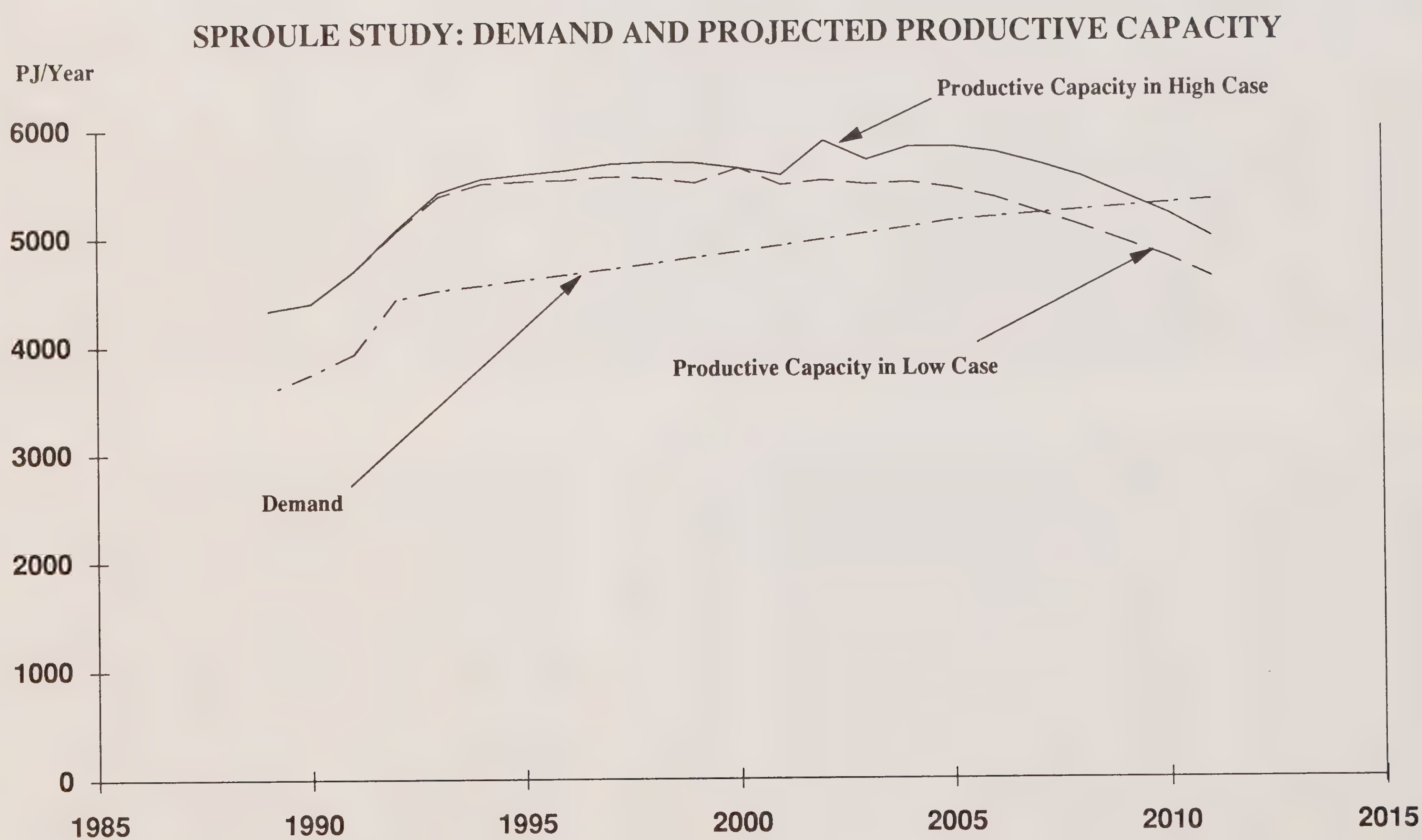
TransCanada submitted that the Sproule model is a gas supply model and does not determine either the total market requirements or the apportionment of the demand for gas from the WCSB. TransCanada stated that the level of demand used in the study was sufficient to allow for growth in domestic demand plus new exports and that there was more than adequate long-term gas supply capability from the WCSB to ensure utilization of the existing and proposed TransCanada facilities at or near capacity. TransCanada further stated that it did not consider it critical to determine the apportionment of overall supply to the various pipeline systems and specifically to markets served by TransCanada. TransCanada stated that, once a particular market region has been chosen and the pipeline infrastructure put in place from the WCSB, it will be difficult and costly to switch to serve some other market region; it took the view that the provision of a sufficient producer netback will ensure that producers continue to serve the market. While noting that the Sproule study of supply capability and the Foster study of market demand were conducted independently, TransCanada referred to the Foster study as evidence that netbacks to producers from the Northeast U.S. market are estimated to be slightly higher than comparable netbacks from other regions.

TransCanada submitted that the adequacy of overall supply had been demonstrated by the Sproule study and that the termination of certain of WGML's supply contracts by its producers should have no impact on the overall supply available to markets served by TransCanada or on the economic feasibility of the proposed facilities expansion.

Views of Intervenors

There was very limited intervenor comment on the Sproule study. The Ministry of Energy for Ontario ("Ontario") questioned Sproule, suggesting that both the assumed reserves to production ratios and the rate at which unconnected reserves were assumed to be connected imply that the Sproule study would give an optimistic assessment of productive capacity. Ontario also noted that the study did not discuss lower productive capacity that could arise due to the potentially poorer quality of unconnected established reserves, from delays in

Figure 19.1


SPROULE STUDY: DEMAND AND PROJECTED PRODUCTIVE CAPACITY
PJ/Year
6000
5000
4000
3000
2000
1000
0
1985
1990
1995
2000
2005
2010
2015
Productive Capacity in High Case
Productive Capacity in Low Case
Demand

producing associated gas and from the location of new discoveries in areas not accessed by existing gathering pipelines. However, Ontario commended Sproule on the thoroughness of the study's statistical analysis.

Several parties did, however, submit views regarding the relevance of contract terminations by WGML's producers to TransCanada's overall supply situation and the assessment of the economic feasibility of the proposed expansion.

While taking no position on the adequacy of WGML's supply evidence, Union noted that supplies which are terminated by WGML's producers may move to other markets which are not served by the TransCanada system. Union suggested that evidence of overall gas supply only provides the Board with assurances that supply is available to the TransCanada system if it is not committed to another market and a buyer in the market served by the TransCanada system wants to purchase it.

IPAC submitted that, although certain parties currently supplying gas to WGML have exercised contract terminations for the 1994/95 contract year, the gas remains available for disposition to markets served by TransCanada. IPAC was of the view that contract terminations had no impact on the overall supply available to markets served by TransCanada and that producers had dedicated their respective gas supplies, through contractual arrangements, to markets served by the proposed expansion.

APMC submitted that TransCanada had met the onus placed on it by the Board to demonstrate the adequacy of overall gas supply with respect to the proposed facilities and that contract terminations by WGML's producers did not materially affect TransCanada's overall supply picture or the economic feasibility of the proposed expansion.

WGML submitted that the termination notices have no impact on the overall reserves picture, as the reserves have not disappeared, but may simply be in different hands after 1994. WGML stated that the overall supply test had been passed, based on the Sproule study's findings, without substantial challenge from any party. WGML further submitted that the market evidence provided by both TransCanada and ANE demonstrated that the U.S. Northeast market exists, that the viability of the connection between market and supply is the most important insurance policy when considering economic feasibility and that this was the most convincing reason why the pipeline would remain useful over its economic life. In response to the concern expressed by Union, WGML submitted that the most likely alternative market would be proposed projects to export gas to California and that the Board would have the opportunity to reassess the adequacy of overall supply during the review of future pipeline proposals.

Views of the Board

The Board is of the view that the overall approach used by Sproule is an acceptable methodology for the projection of supply capability from the WCSB and concurs with TransCanada that many of the assumptions of the Sproule study are appropriate for basin-wide supply analysis. However, the Board has identified a number of specific concerns pertaining to the study methodology and assumptions. These are discussed below.

Sproule's projection of future reserves additions is in part based on a statistical relationship between cumulative reserves additions and cumulative gas-directed drilling activity. Sproule demonstrated that a power function provided a good statistical fit for the historical data and used this function as the basis for the projection of future reserves additions. This function would suggest that cumulative additions increase continuously with cumulative drilling, but at a progressively declining rate. Given an estimate of ultimate gas-directed drilling footage, an estimate of the WCSB's ultimate natural gas potential could be inferred. Sproule referred to a study by WGML which had estimated the ultimate gas-intent metreage on the basis of assumptions regarding the ultimate well spacing and average well depths for various regions of the WCSB. At this ultimate drilling level, cumulative additions would be about 240 Tcf. Sproule indicated that independent geological support for this estimate was beyond the scope of their study, that ultimate potential cannot be estimated precisely and that their inferred total, plus or minus twenty per cent, should encompass the plausible range of estimates of ultimate potential.

The Board is concerned that the very high correlation coefficient obtained by Sproule for the

relationship between cumulative drilling and cumulative reserves additions overstates the certainty with which trends of this nature can be estimated. The Board is of the view that there is a much larger degree of uncertainty regarding the projections derived using the reserves additions model than suggested by the statistical correlations referenced in the study and notes that Sproule did not investigate the impact of alternative finding rate projections on the forecast of natural gas supply capability from the WCSB. The Board agrees with Sproule that ultimate potential cannot be estimated precisely and recognizes that an estimate of ultimate potential for the WCSB is not required to develop the reserves additions projection using the Sproule model. However, the Board is of the view that, in developing finding rate projections over the longer term, consideration should be given to the plausible range of estimates of ultimate potential and questions whether the particular formulation used in the study would be consistent with an ultimate potential estimate toward the lower end of the range of estimates suggested by Sproule, the range being 240 Tcf plus or minus twenty per cent.

Sproule's projection of reserves additions is also largely based on a model of gas-directed drilling activity which relates total gas-directed drilling activity to net gas revenues (the gas price, less average operating and processing costs and average royalties, per Mcf of gas), to the cost of yearly gas reserves additions (a four-year moving average expressed as $/Mcf), to annual gas sales, to a measure of productive capacity relative to requirements and to cumulative drilling. In developing this model, Sproule tested a number of different variables. Sproule stated that the variables finally selected for the specification of the industry activity equation gave a better fit for the historical period than possible alternative variables. Sproule thought it likely that drilling costs, well operating costs, and the costs of other industry activities likely will change with oil and gas prices. Thus, to project net gas revenues and the cost of future reserves additions, two of the explanatory variables of the drilling activity model, Sproule developed statistical relationships between industry activity costs and an index of oil and gas prices.

The activity model developed by Sproule is of considerable interest to the Board and it is evident that an extensive amount of analysis has been devoted to deriving the statistical relationships used in the model. The Board finds the overall approach used by Sproule to project activity acceptable, but has some reservations about certain elements of Sproule's activity model. On the basis of the Board's review of the activity model, it would appear that Sproule selected a model specification which results in somewhat higher levels of activity and productive capacity during the estimation period than may be appropriate, given the particular price and demand projections used in this analysis.

The Board's views in this regard are based on the following considerations:

(i) resource depletion may have a greater influence on unit costs than was reflected in the Sproule analysis;

(ii) relating unit costs to oil and gas prices, as was done in the Sproule study, implies that costs will remain constant once oil and gas prices are constant, whereas in fact there may be continued escalation of costs;

(iii) to the extent that there may be more exploratory drilling and less development activity than projected by Sproule in the future, the projected cost of reserves additions would be higher; and

(iv) the manner in which the explanatory variables in the activity equation were selected and used in the subsequent analysis.

The somewhat higher level of activity during the projection period would seem to be at the expense of sharply dropping activity thereafter.

TransCanada submitted that the Sproule study demonstrates that there is sufficient supply capability to satisfy the assumed level of demand for Canadian gas over the majority of the projection period. The Board notes that the study results indicate that the projected demand could exceed the supply capability from the WCSB toward the end of the projection period. However, by that time the Board considers it reasonable to expect that production from alternative sources, for example from reserves in the Mackenzie Delta

or unconventional supply sources such as tight gas or coalbed methane, would be available at the prices assumed in the analysis.

TransCanada did not address the supply capability from the WCSB beyond the period examined in the Sproule study (i.e. post 2011). However, it is evident from the trends in productive capacity that there would have to be an increasing reliance on frontier supply sources or unconventional supplies, or alternatively that the conventional supply capability would have to be higher than suggested by Sproule, if the demand levels projected in the study are to be sustained. While recognizing the uncertainties associated with projections of supply in the distant future, the Board notes that TransCanada did not comment on supply availability beyond the study period during the course of the hearing.

Notwithstanding the above-noted concerns, the overall supply capability projected by the Sproule study for the WCSB is well within the range that the Board considers plausible, given the uncertainty inherent in many of the underlying assumptions. The Board encourages TransCanada to consider the issues outlined above and, particularly, to reflect the uncertainty inherent in many of the analytical parameters used in the analysis, in conducting future studies of this nature.

TransCanada submitted, and the Board concurs, that the Sproule model is a gas supply model only and does not address the extent to which the available gas supply will actually flow through the TransCanada system to markets in Eastern Canada and the Northeast United States. The Board is of the view that there should be an effort made by TransCanada to further integrate its studies of overall supply capability and market demand in assessing the longer term utilization of its total pipeline capacity, including the applied-for expansion.

Finally, the Board concurs with those parties who submitted that contract terminations by WGML's producers do not alter the overall availability of supply from the WCSB, in the sense that the physical reserves continue to exist. However, the Board agrees with Union's submission that contract terminations and/or potential volume reductions can have an effect upon the extent to which there is a contractual commitment of reserves to WGML, which has traditionally supplied a substantial portion of the market in Eastern Canada via the TransCanada system. It is possible that some of the established reserves removed from WGML's supply pool through contract terminations will be diverted to other markets through other existing or proposed pipeline systems. The extent to which this has an impact on the ability of purchasers in market areas served by the TransCanada system to secure alternative supplies from the WCSB and on the utilization of the total capacity of the pipeline will depend on the availability of gas supply from reserves additions or uncommitted reserves and on the competitiveness of the netbacks in these markets relative to those in other markets not served by the TransCanada system. On the basis of the overall supply evidence provided by the Sproule study, the market evidence described in Chapter 20 of these Reasons and the specific contractual arrangements related to the proposed expansion, the Board is satisfied that the overall utilization of the TransCanada system in the longer term is not likely to be affected significantly by contract terminations by WGML's producers.

In summary, the Board is satisfied that there will be an adequate natural gas supply to ensure sufficient utilization of the TransCanada system, including the proposed expansion.

Chapter 20
Requirements

20.1 Overall Natural Gas Demand in Quebec, Ontario and Manitoba

As part of its application, TransCanada provided a long-term forecast of requirements for natural gas in Quebec, Ontario and Manitoba, unconstrained by pipeline capacity, for the period through to the year 2005.

TransCanada's forecast assumed that the world oil price would remain at about U.S. $19.55 per barrel in 1990. During 1990-95, TransCanada projected that real world oil prices would increase by 4.7 percent per year as a result of the tightening of world demand and stronger Organization of Petroleum Exporting Countries cohesiveness. According to TransCanada, in the post-1995 period, stability of demand and supply conditions would reduce growth in real world oil prices to 1.8 percent per year.

With regard to natural gas prices, TransCanada expected the current gas surplus to dissipate by 1990, leading to an increase in the price of natural gas relative to oil. After 1993, TransCanada assumed that the prices of natural gas and heavy fuel oil to the Ontario industrial market would grow at the same rate. As a result, the industrial burner-tip price of natural gas in Ontario will lose some of its advantage relative to heavy fuel oil and electricity, but remain competitive. In Quebec, natural gas is already more expensive than both heavy fuel oil and electricity in the industrial sector.

According to TransCanada, despite the expected competitiveness of natural gas, the electrification of industrial processes would lead to a slight decline in the market share of natural gas in the industrial sector in Ontario. For Quebec, TransCanada estimated that the termination of existing incentive programs by Hydro-Québec would enable natural gas to capture one-third of the boiler market and increase its share of the industrial sector in that province.

Table 20-1 presents TransCanada's forecasts of end-use natural gas requirements for Ontario and Quebec and Firm Service volumes currently contracted with Canadian customers in those provinces.

The uncontracted volumes shown include both potential firm and interruptible sales, and/or imports required to meet the unconstrained demand forecast in column 1.

TransCanada also provided two forecasts of natural gas demand for Manitoba, Ontario and Quebec illustrating the impact on gas demand of alternative assumptions regarding economic growth and fuel efficiencies. In the high case, the growth rate of housing stock and real domestic product ("RDP") was a half-a-percent a year higher than the base case and energy efficiencies improved at half the rate it assumed in the base case. In the low case the growth in housing stock and RDP was lower than the base case by half a percent per year and the change in energy efficiency twice the base case rate. Table 20-2 compares TransCanada's high and low end use forecasts with its base case forecast for selected years.

Intervenors questioned TransCanada regarding the possibility of natural gas/heavy fuel oil competition in the industrial markets in Quebec and Ontario. According to TransCanada, switching between oil and gas in certain Ontario industrial markets, such as Sarnia, is limited by the lack of available infrastructure to take heavy fuel oil into industries. In TransCanada's opinion, switching in Quebec industrial markets is constrained by the reluctance of refineries to cut heavy fuel oil prices, since this action would also entail cutting prices for customers not accessible by a natural gas pipeline.

Intervenors also questioned TransCanada regarding the impact on demand for natural gas in Ontario of a $0.10/GJ (later revised to $0.09/GJ) increase in the transportation toll. Assuming that the toll would increase the delivered price of natural gas relative to the base case, TransCanada estimated that the impact of such a toll on demand for natural gas would be

Table 20-1

TransCanada's Forecast of Requirements Ontario and Quebec

10^6m^3 (Bcf)[1]

Year	Total Demand[2] Ont./Que.	Provincial Supply	FS Deliveries Ont./Que.	Not Contracted Ont./Que.[3]
	(1)	(2)	(3)	(4)
1991[4]	29 880 (1055)	800 (28)	27 870 (983)	1 210 (43)
1992	30 984 (1094)	800 (28)	27 870 (983)	2 314 (82)
1995	33 564 (1185)	800 (28)	27 870 (983)	4 894 (173)
2000	36 551 (1290)	800 (28)	27 870 (983)	7 881 (278)

Source: Exhibit B-1, Tab "Requirements", Sub-tab 2, Table 7

1. 1 cubic metre = 35.3 cubic feet.
2. Includes distribution uses and end-use demand.
3. Derived as Column (1) less Columns (2) and (3).
4. Year commencing 1 November.

Table 20-2

Comparison of TransCanada's Three Forecasts of Canadian End Use Demand

Total Demand for Manitoba, Ontario and Quebec

PJ (Bcf)[1]

Year	Low	Base	High
1991	1 121.5 (1065)	1 154.3 (1097)	1 184.8 (1126)
1992	1 140.0 (1083)	1 180.6 (1121)	1 224.7 (1163)
1995	1 213.1 (1152)	1 279.4 (1215)	1 370.2 (1302)
2000	1 302.6 (1237)	1 417.1 (1346)	1 598.0 (1518)
2005	1 368.2 (1300)	1 539.6 (1463)	1 835.6 (1744)

1. 1 PJ = 0.95 Bcf

negligible. TransCanada felt that the risks from changes in tolls are minor compared to the risks due to changes in economic growth, fuel prices and fuel availability.

In response to an information request from the Board, TransCanada addressed the impact of weakening economic growth on its projected load forecasts and capacity requirements for domestic service. TransCanada concluded that the potential decline in uncontracted demand (see Table 20-1) resulting from an economic downturn, would be a reduction in 1991 levels from 1 206 10^6m^3 to 800 10^6m^3. Thus, TransCanada concluded that there would still remain potentially unsatisfied Canadian gas demand after the proposed expansion.

With respect to competition from natural gas imports to TransCanada's market in Eastern Canada, the APMC argued that U.S. gas imports into Eastern Canada are not likely to increase due to capacity constraints on the importing pipelines in the short term. The APMC further argued that any increase in imports would likely serve incremental domestic growth, rather than displace volumes related to this capacity expansion. Union concurred that TransCanada's forecast of domestic requirements is reasonable, even in the face of increasing imports. GMi argued that it is essential that Canadian natural gas and transportation remain competitive in the context of a North American market, if it is not to be threatened by supplies of competitive U.S.-sourced gas through increased imports.

Views of the Board

Since TransCanada submitted its forecast of domestic natural gas demand, there have been major changes in several of its original assumptions. Oil prices escalated rapidly in late 1990, before settling back to the $25-27 (U.S. per barrel) range by year end, and economic growth deteriorated more quickly than expected. TransCanada has provided its assessment of the impact of varying economic growth and efficiency assumptions on its outlook for domestic natural gas. Given the range of plausible assumptions and results, the Board finds TransCanada's assessment of domestic natural gas requirements to be reasonable.

TransCanada's forecast and sensitivities, including its observations on the impact of lower near-term economic growth, suggest that domestic demand might exceed that provided for by the current capacity expansion, in the medium term and that with competitive conditions for natural gas, these requirements would result in a long-term need for the proposed domestic capacity.

The Board encourages TransCanada to continue to review a range of plausible assumptions and forecasts in assessing the long-term domestic requirements for natural gas. While this is an ongoing process, requiring time and resources, the Board believes that such assessments are critical to a thorough understanding of long-term markets, and associated pipeline capacity, given the increasing complexity of energy markets and demand.

In summary, the Board finds TransCanada's assessment of long-term domestic requirement to be reasonable and concurs that imports of natural gas from the U.S. should not pose a major threat to the utilization of the proposed capacity destined for domestic purposes.

20.2 Overall Natural Gas Demand in the U.S. Northeast

TransCanada's application is based on an expansion largely to serve the U.S. Northeast gas market. The evidence in this proceeding illustrates the divergence in expert opinions particularly with respect to the strength and the risk of this market in the long term. Two major studies were submitted: the Prospective U.S. Natural Gas Market (Update) prepared by Foster Associates, Inc. ("Foster") on behalf of TransCanada, and The U.S. Northeast Demand for Canadian Natural Gas prepared by Jensen Associates, Inc. ("Jensen" or "JAI") for Consumers'.

Intervenors' major concerns about the potential for increased penetration of natural gas in the U.S. Northeast and the role of Canadian supplies included the size of the market, the risks to natural gas use in the power generation sector, the relative competitiveness of Canadian natural gas in this market, and the economic incentives for shippers to honour their contracts.

The Foster study updated and expanded an earlier study prepared for TransCanada in the GH-1-89 proceeding. The projection of gas demand indicated that increases are expected in all sectors of the U.S. Northeast market. In total, Northeast gas demand is projected to increase by 817 Bcf from 2225 Bcf in 1988 to 3042 Bcf by 2010 (see Table 20-3).

Underlying the Foster forecast are assumptions that: the oil price (refiners acquisition costs ("RAC")) rises to $36 U.S. per barrel (1989 dollars) in 2010; the equilibrium wellhead price of gas increases to $3.31 in 2000 and $4.11 U.S. 1989 dollars per MMBtu in 2010; and economic growth in the U.S. Northeast ranges between 2.0 and 2.5 percent per year over the forecast period.

In the Foster study, the prospective growth in the Northeast gas market reflects the conversion potential from existing fuel oil customers in all sectors (due to low saturation of gas used for heating), the greater use of gas to generate power as a result of the competitive price of gas, the current low market share, and increasing environmental concerns.

The study indicates that conventional supply of natural gas from the Lower 48 States, estimated at 16.7 Tcf in 1988, is projected to decline to 14.3 Tcf by 2010. The largest declines in production capability are expected in the South Louisiana and Texas Gulf Coast areas, the main producing areas currently supplying the Northeast market. As a result, total supplemental Northeast gas requirements are projected to increase from 0.1 Tcf at present to 1.3 Tcf in 2010. Foster recognizes that Canadian gas will have to compete with other supplies in order to capture its share of this potential market. TransCanada believes that Canadian gas has a competitive advantage over these supplies stemming from relatively less expensive transportation costs to the market when compared to LNG supplies, relative market confidence in the reliability of Canadian supplies, a desire to diversify supply sources, the known level of Canadian proven reserves and potential resource base, and the relatively lower cost of developing Canadian reserves.

In the JAI forecast prepared for Consumers', oil prices (RAC) reach $24.46 U.S. per barrel (1989 dollars) in 2005. In the same year, the natural gas wellhead prices average $3.65 U.S. 1989 dollars per MMBtu. JAI assumes that economic growth in the Northeast will be 2.6 percent from 1990 to 1995 and 2.3 percent from 1995 to 2005.

Relative to the 1988 demand level, natural gas demand in the Jensen study is projected to increase by 164 Bcf to 2336 Bcf in 1995, and decline thereafter to 2304 Bcf in 2005 as a result of a reduced residential requirements. The growth in the demand for natural gas in the U.S. Northeast is projected to be greatest in the electric power generation sector. By the year 2000 the projection of gas demand in the power generation sector is estimated at 399 Bcf. JAI indicates that there is an upside potential, described as more speculative, that could add another 260 Bcf to the power sector projection by the year 2000, resulting in total Northeast demand of 2593 Bcf. Jensen acknowledged during cross examination that it is likely that its base case demand forecast will be exceeded.

JAI cited as motivations for purchasing Canadian gas in the Northeast: the desire for long-term supplies with specific escalation clauses, increased competition, and a diversification of supply. To assess the competitiveness of Canadian supplies, JAI analyzed the ANE and Boundary gas contracts and submitted that the price of Canadian gas delivered at 100 percent load factor to the Northeast will be more expensive than U.S. supplies during the early years. At lower load factors, Canadian gas will have a larger price disadvantage that will last longer. However, JAI believes that Canadian gas will have an incremental cost advantage over U.S. supplies as long as there is an obligation to pay the demand charges.

One major conclusion of the Jensen study is that the increase in demand for Canadian gas in the Northeast, at levels projected by TransCanada, will displace a significant amount of U.S. production from Appalachia and the Gulf Coast. The displacement conclusion in the JAI study is of particular importance in Consumers' view. The utility is concerned that the displacement would make the U.S. Northeast a highly competitive market as it would increase the gas-on-gas competition. Consumers' also expressed concern about a number of risks that could result in Canadian gas being taken at a lower load factor than that projected by TransCanada. These

Table 20-3

Comparison of Forecasts of Lower 48 States Production, U.S. Northeast Gas Demand and Oil & Gas Prices

	Lower 48 States Production (Tcf)		Northeast Gas Demand (Bcf)		Oil Price - RAC (US 1989 $/bbl)		US Gas Wellhead Price (US 1989 $/MMBtu)	
	Foster	**JAI**	**Foster**	**JAI**	**Foster**	**JAI**	**Foster**	**JAI**
1995	16.9	14.2	2584	2336	25.00	19.65	2.50	2.63
2000	16.0	14.2	2809	2333	30.00	22.89	3.31	3.24
2005	15.1	14.1	2966	2304	33.00	24.46	3.55	3.65
2010	14.3	n/a	3042	n/a	36.00	n/a	4.11	n/a

Source: 1. TransCanada's response to the Board's Information Request No. 58; Tables 58-D, 58-F, 58-K.
2. Jensen Associates, Inc., The U.S. Northeast Demand for Canadian Natural Gas, Tables I-A-1, I-A-2, II-B-3.

include: the implementation of gas supply charges in the U.S. and changes in transportation rate structures, the effect of contractual arbitration terms and oil price shocks, system supply gas prices coming in line with the market faster than expected, the cost of producing U.S. gas relative to Canadian gas being lower than assumed, and lower gas takes by independent power producers or non-utility generators. They further discussed risks that would arise because of the large component of the projected demand that depends on the power generation sector. Consumers' argued that it is extremely difficult to get a measure of the potential in this market, in particular for the requirements of the non-utility generators ("NUG") and independent power producers; that the economic viability of power generation projects will be affected by the highly competitive nature of this sector; and that small changes in demand projections for electricity have large implications for natural gas demand. It is the inherent riskiness of the power generation sector that caused JAI to distinguish between base load gas demand and a more speculative upside potential in the power sector. The JAI study concludes its assessment of the risks to U.S. demand for Canadian gas by stating that, since Canadian gas will have an incremental cost advantage over U.S. supplies, it will be taken at a high load factor.

Notwithstanding this statement, Consumers' believed that the Foster forecast of Northeast gas demand was unrealistically high. Consumers' argued that Foster's gas price forecast is disproportionately low relative to the high oil price assumption in its study, and this leads Foster to overstate the competitiveness of gas. Further, Consumers' argued that demand in the residential sector is overstated as a result of inappropriate assumptions about the growth in the residential housing stock. GMi also was concerned that the U.S. Northeast gas demand could be overestimated in the Foster projection, particularly in the residential and power generation sectors where optimistic assumptions are made. GMi believed that there are real possibilities that a lower demand in the U.S. Northeast coupled with higher U.S. gas supplies may lead to a situation where Canadian gas will have to compete with and displace U.S. supplies.

There are a number of areas in the JAI study with which TransCanada took issue. TransCanada stated that the displacement of U.S. gas supplies to the Northeast by natural gas from Canadian sources is not possible if U.S. gas supplies are not available to be displaced by Canadian gas. In this context TransCanada contended that JAI forecasts a decline in U.S. conventional gas production levels and that JAI recognizes the LDCs' motivations for purchasing Canadian gas. TransCanada maintained that the competitive price advantage of fuel oil over gas in the JAI study is unrealistic and that the market growth in the Northeast is underestimated.

There is a major difference of view between Foster's and JAI's estimates of the gas requirement in the electric power sector. In the Foster study the growth in gas requirements for power generation is projected to average 5.9 percent per year from 230 TBtu in 1988 to 606 TBtu in 2005. JAI projects these requirements to be 406 TBtu by 2005, an average growth of 3.4 percent per year. For its part, TransCanada indicated that the North American Electric Reliability Council forecasts electricity growth of about two percent per year for 1989 to 1998 in the Northeast area and an important proportion of this increase would be generated by gas.

At the hearing the forecasts of Foster and JAI were compared to those of various private and government organizations (see Table 20-4). This comparison shows the outlooks of JAI and Gas Research Institute ("GRI") to be similar, with EIA expecting little growth in that region. The projection of Foster, on the other hand, indicates a substantially larger role for gas over the next fifteen years.

The major sectoral differences in these outlooks are in the residential, industrial and power generation sectors. The Foster forecast shows continued growth in residential gas use, reaching about 18 percent above 1987 levels in 2005. However, JAI is of the view that the share of natural gas in residential use will increase over the medium term, but as efficiency improvements are reflected in energy-using equipment, residential gas use will decline to a level 8 percent above that in 1987. The GRI and EIA projections for residential use also show only modest gains, to a level close to that of JAI.

Table 20-4

Comparative Northeast Gas Demand Forecasts

(Bcf)

	Foster	GRI	EIA	JAI[1]
1988	2225	2225	2225	2225
1990	2317	2246	N/A	2218
1995	2584	2226	2310	2393
2000	2810	2332	2298	2390

Source: Exhibit D-19-28, page 13.

1. The levels differ from those in Table 20-5 for JAI due to the addition of lease plant and pipeline fuel.

Comparison of industrial and power generation demands are difficult due to different accounting conventions for non-utility generation by different organizations. The Foster and JAI studies do not differ significantly in their outlook for non-utility generation, each expecting less than 150 Bcf gas demand for this use by the year 2000. The Foster outlook shows industrial gas use almost 40 percent higher by 2000, while JAI expects only a 25 percent gain relative to 1987 demand.

One of the largest differences in the outlooks is for electric utility use. Foster shows almost 470 Bcf demand in the year 2000, while JAI and GRI are at about 275 Bcf, and EIA higher at 357 Bcf. As mentioned above, however, JAI suggested that there is an upside risk in this area which could add another 260 Bcf to the non-utility and electric power sector demands by the year 2000. This increment would bring the outlooks for the electric generation sector for Foster and JAI to similar levels, with remaining differences in the residential and industrial sectors.

ANE argued that conclusions drawn from analyses for the entire Northeast area are not representative of its particular service area situation. ANE stated that its service areas represent a growing market for natural gas characterized by a high dependence on imported oil, low saturation rates for natural gas, pipeline capacity constraints, growing electric power requirements and increasing environmental constraints on the use of oil and coal. In ANE's view, additional gas supply is needed to meet expanding market requirements and domestic natural gas. ANE believes that if any displacement occurs in its service areas it is more likely to be displacement of imported oil. ANE argued that in all sectors in the ANE service areas the oil share of total energy requirement is significantly higher than in the rest of the U.S. ANE believes that gas requirements for power generation are expected to increase dramatically as environmental legislation and the availability of gas supply and pipeline capacity is expected to favour gas sales in the power sector of its service areas. ANE also expressed its disagreement with respect to the assessment of ANE contracts, and the assessment of risk as conducted by JAI. The pricing provisions in the ANE contracts incorporate adjustments to recognize the seasonal nature of competitive fuel in the marketplace. According to ANE, JAI's analysis failed to recognize the nature of the pricing mechanism of the ANE contracts and based its conclusions on an assumed annual average price for ANE that is not indicative of the competitiveness of its supplies. ANE disagreed with JAI's contention that most of the NUG capacity is must run and that it would face significant risk if it were to become dispatchable. It indicated that most of the major gas-fired cogeneration projects in the ANE market area are dispatchable. Finally, ANE argued that its structure insures that several layers of financial security stand behind the long-term commitments made to TransCanada.

Union described the proposed expansion as a project exposed to substantial risk of under-utilization because of the competitiveness of the Northeast market. Union indicated that future demand for natural gas depends on the development of gas-fired electrical generating capacity and also on the success with which gas will displace oil. It also indicated the possibility that new pipeline capacity may change the market structure, and that in case of "reoptimization" of the North American market (in which structural realignments would occur to minimize costs to consumers or maximize producer netbacks) it is likely that Canadian gas would be devoted to California and the midwestern and northwestern U.S., while the Northeast would generally be served by supplies from the U.S.

Enserch and IPAC concurred with evidence given by the Consumers' Northeast Market Panel that the demand projections set forth in the JAI study would likely be exceeded, that Canadian gas would have an incremental cost advantage over U.S. supplies, and would be taken at high load factor.

TransCanada argued that the potential for under-utilization of its proposed expansion is low. It indicated that market-sensitive pricing provisions as well as renegotiation and arbitration mechanisms in the gas sales contracts will mitigate the competitive pressure that would be associated with a lower-than-expected Northeast gas demand. U.S. buyers' concerns about the lack of available U.S.-sourced, long-term supply favours the willingness of parties to enter into gas purchase contracts, and reduces the probability of a loss of Northeast gas market share for Canadian gas. TransCanada argued that its proposed

expansion to the U.S. Northeast offers a transportation cost advantage over the higher profile alternatives that are being discussed for the transportation of Canadian gas. Also, evidence of market support is provided by the fact that gas sales and transportation contracts are in place. In addition TransCanada believes that the obligation to pay the demand charge is a significant economic incentive for shippers to continue to use its system for the term of the transportation contracts. TransCanada argued that the risks associated with the cogeneration market should be placed in perspective, indicating that this market accounts for 27 percent of the volumes destined for the U.S. Northeast in this application and that each project is relatively small. TransCanada believes that if some projects actually failed, the strong growth in demand in its market is an important factor which would mitigate the long-term risk of expansion. Consumers' urged the Board not to assume that if some projects were to terminate prematurely the demand for Canadian gas would be such that other projects will always be waiting to contract for the vacated capacity.

TransCanada was asked by the Board to address the impact on natural gas demand and throughput in the near-term of a possible sharp decline in economic activity. The current economic situation for the U.S. is characterized by TransCanada as a slowdown that is expected to last well into 1991. In light of the high gas demand level for 1989, the increase in the world oil price experienced since mid-1990, and an economic recovery expected to commence in late 1991, TransCanada believes that the current projection of gas demand for 1990 and 1995 in the Foster study is reasonable. The 1991 consumption should be about the same as 1990. All export shippers under this facilities application have indicated that their forecasts have not changed significantly as a result of current conditions.

Views of the Board

Having considered the evidence presented during the hearing of the forecasted use of natural gas in the U.S. Northeast, the Board is of the view that there is a long-term market for natural gas in that region. The two projections show differing views of the volumes, or growth in the market over the long run. The Board agrees that this is a highly competitive market, as growth is dependent on residential conversion, increased use of gas in the power generation sector and maintenance of a competitive position with respect to other fuels and other sources of natural gas. Uncertainty with respect to the size of the market increases over time.

While there are projections of natural gas demand for the Northeast which are higher than the Foster outlook in the year 2000 and beyond, and several that are somewhat below that of JAI in the same period, the Board agrees with the observation of Consumers' that the risk to these lower outlooks is on the upside, and that demand could well be higher than JAI has projected. However, this demand can be met from a number of sources including Canadian supply. Of the volumes to the United States under consideration for the Part III expansion, about 70 percent are destined for system supply of U.S. local distribution companies, and the balance is for cogeneration plants. Local distribution companies will include Canadian gas if it is priced competitively in their portfolio of supply, which will reduce the risk from demand materializing only in certain sectors of the region. Those volumes for cogeneration will face risks specific to the individual projects as well as the competition faced by all volumes of gas in this competitive market.

However, contracts have been signed and commercial agreements made which indicate a market for gas and a role for Canadian supplies at least over the periods of the contracts underpinning the expansion, generally in the range of 15 years. The evidence filed at the proceedings suggests to the Board that Canadian gas could continue to compete for Northeast markets beyond the initial contract period, using the facilities under consideration.

20.3 Specific Transportation Services

In support of its facilities design, TransCanada provided forecasted winter maximum daily demand and annual delivery requirements, by class of service, for the contract years commencing 1 November 1989, 1990, 1991 and 1992, as well as estimated annual system deliveries for its customers to the year 2001. Table 20-5 shows the forecast contract service requirements for the

Table 20-5

TransCanada's Forecast of Annual FS Deliveries [1]

Contract Year	Domestic[1]		Export		Total		% Increase from Previous Year
	10^9m^3	Bcf	10^9m^3	Bcf	10^9m^3	Bcf	
1989/90	30.1	1 062	12.4	438	42.5	1 500	N/A
1990/91	30.8	1 087	19.6	692	50.4	1 779	18.6
1991/92	32.0	1 130	26.9	949	58.9	2 079	16.9
1992/93	32.0	1 130	27.9	985	59.9	2 115	1.7

Source: Exhibit B-1, Tab "Requirements", Table 1 as revised March 1990.

1. Includes STS and exchange volumes.

contract years commencing 1 November 1989, 1990, 1991 and 1992.

TransCanada submitted that its amended facilities application was designed to provide domestic and export sales and transportation service to accommodate the forecast requirements set out in its application. The forecast requirements consisted of the existing Canadian market, including growth, the existing export market, including growth, and new export projects. The increase in demand is due almost entirely to the attachment of growing export markets in the U.S. Northeast.

TransCanada advised that its forecast of domestic and export deliveries shown in the requirements tables of the application is based on existing contracts and discussions with both existing and prospective shippers.

The first section on Canadian markets discusses TransCanada's forecast of firm service requirements. The subsequent section on export markets deals with specific projects advanced in support of the proposed facilities.

20.3.1 Canadian Markets under Firm Service Contract

The proposed facilities were designed to accommodate, *inter alia*, increases in load factors for certain existing domestic customers and incremental services to several new and existing domestic customers.

The overall domestic incremental requirements, for which facilities had been applied, constituted the most assured system requirements. The most assured system requirements, which underpin those facilities already certificated in TransCanada's application for partial facilities, are fully described in System Requirements, Volume 2, Chapter 2 of these Reasons for Decision. For the convenience of the reader, these amended Canadian incremental requirements and the amended listing of new firm services for export, both associated with the facilities application, are summarized in Table 20-6.

20.3.2 Export Markets

TransCanada's forecast of 1991/92 export requirements included:

- current service, with some adjustments, for winter max day deliveries of approximately 68.873 $10^6m^3/d$ (2432 MMcfd) to existing export markets;
- new services for the twelve export licences filed in this hearing in support of the proposed facilities for winter max day deliveries of 7.234 $10^6m^3/d$ (255.4 MMcfd);
- new service for the ANE and Shell Granite State projects which were previously licensed for winter max day deliveries of 9.127 $10^6m^3/d$ (322.1 MMcfd); and
- new service for FSC Plattsburgh and Power City Partners to replace capacity relinquished to CanStates for winter max day deliveries of 1.372 $10^6m^3/d$ (48.4 MMcfd).

20.3.2.1 Current Export Services

TransCanada's forecast of 1991/92 export requirements included estimated export deliveries of 68.873 $10^6m^3/d$ (2 432 MMcfd) for those export services currently flowing or expected to flow before November 1992 pursuant to existing long-term export arrangements. Included in this forecast were adjustments for increases and decreases in load factor, deletions of existing service, increases in service under existing contracts, reversion, and adjustments related to contractual changes.

TransCanada's base case export requirements included export services previously reviewed by the Board during the GH-1-89 proceeding and scheduled to commence deliveries during the 1990/91 contract year.

20.3.2.2 New Services Sought Under Part VI of This Proceeding

The proposed 1991/92 requirements forecast also included proposed transportation services for which twelve export licences are being considered in these proceedings. These new firm services totalling 7.234 $10^6m^3/d$ (255.4 MMcfd) are also indicated in Table 20-6 and are discussed in Chapters 3 through 17.

Table 20-6

New Firm Services Associated with TransCanada's December 1989 Application

Shipper / Buyer	Delivery Area	Start Date	$10^6m^3/d$	MMcfd
Domestic				
Simplot Chemical	Manitoba	Nov 91	.070	2.5
Union	Central	Nov 91	1.320	46.7
Gaz Métropolitain	Eastern	Nov 91	1.530	54.0
ICG (Ontario)	STS-Eastern	Nov 91	.300	10.6
Gaz Métropolitain	STS-Eastern	Nov 91	.680	24.0
	Domestic Total*		**2.920**	**103.2**
Export				
@ Emerson, Manitoba				
Kamine Besicorp South Glen Falls**		Nov 91	.402	14.2
@ Niagara, Ontario				
WGML/Elizabethtown**		Nov 91	.283	10.0
Can Oxy/Long Island Cogen**		Nov 91	.460	16.3
Niagara export sub-total			.743	26.3
@ Chippawa, Ontario (Empire State)				
Kamine Besicorp Carthage/Carthage Cogen**		Nov 91	.402	14.2
Ecogen Four Partners/American Brass**		Nov 91	.425	15.0
Indeck/Corinth Cogen**		Nov 91	.496	17.5
Fulton/Nestlé-Fulton Cogen**		Nov 91	.354	12.5
Chippawa export sub-total			1.677	59.2
@ Iroquois, Ontario				
AEC/Alberta Northeast		Nov 91	.399	14.1
ATCOR/Alberta Northeast		Nov 91	.790	27.9
ProGas/Alberta Northeast		Nov 91	1.399	49.4
WGML/Alberta Northeast		Nov 91	5.547	195.7
JMC Selkirk/Selkirk Cogen**		Nov 91	.652	23.0
Brymore/Pawtucket Cogen**		Nov 91	.360	12.7
ProGas/MASSPOWER**		Nov 91	.708	25.0
Shell Canada/Granite State		Nov 91	.992	35.0
Esso Resources/Boston Gas**		Nov 91	.992	35.0
New England Power/New England Power**		Nov 91	1.700	60.0
1991 Iroquois export sub-total			13.539	477.8
@ Iroquois, Ontario				
AEC/Alberta Northeast		Nov 92	.134	4.7
ATCOR/Alberta Northeast		Nov 92	.267	9.4
ProGas/Alberta Northeast		Nov 92	.471	16.6
WGML/Alberta Northeast		Nov 92	1.963	69.3
1992 Iroquois exports sub-total			2.835	100.0
@ Cornwall, Ontario				
Power City Partners		Nov 92	.567	20.0
@ Napierville, Quebec				
FSC Resources		Nov 92	.805	28.4
Export Total		**Nov 91**	**16.361**	**577.5**
		Nov 92	**4.207**	**148.4**
			20.568	**725.9**
Domestic and Export Total*		**Nov 91**	**19.281**	**680.7**
		Nov 92	**4.207**	**148.4**
			23.488	**829.1**

* The Domestic Total does not include STS service.

** These proposed transportation services are also the subject of export licence applications being considered in the GH-5-89 proceedings.

20.3.2.3 New Services for Previously Licensed Projects

New export services to ANE and Shell Canada/Granite State of 9.127 $10^6m^3/d$ (322.1 MMcfd) for export at Iroquois, Ontario which have received long-term export authorizations pursuant to previous Board hearings were included by TransCanada in its 1991/92 requirements forecast and are so indicated in Table 20-6.

20.3.2.4 New Services for FSC - Plattsburgh and Power City Partners

FSC - Plattsburgh

TransCanada included 805 $10^3m^3/d$ (28.4 MMcfd) of exports to FSC at Napierville, Quebec, required to compensate FSC for the capacity previously approved in GH-1-89, but which FSC relinquished to TransCanada's facilities application queue ("FAQ") so that it could serve the CanStates project during the 1990 contract year. FSC will use this gas supply to service three cogeneration plants proposed to be constructed in the Plattsburgh, N.Y. area.

FSC total requirements have previously been examined in the GH-1-89 and GH-6-89 proceedings. FSC obtained export licence No. GL-138 which provides for a term commencing March 1991 with a step-up in volume in February 1993. The timing of commencement of initial service to FSC resulting from the GH-1-89 approval and the increased service resulting from the GH-5-89 capacity fall within the period specified in the licence.

With the necessary regulatory approvals in place in 1991, FSC will be in a position to commence taking its initial gas on 1 April 1992, the date by which the Napierville Extension is expected to be completed, and to take its full volumes on 1 November 1992, the date by which the additional upstream capacity on TransCanada resulting from GH-5-89 is expected to be completed.

Power City

TransCanada also included 567 $10^3m^3/d$ (20 MMcfd) to Power City for export at Cornwall, Ontario. Similar to the FSC situation, this capacity is required to compensate Power City for the capacity which had previously been approved in GH-1-89 but which Power City relinquished to TransCanada's FAQ, in order to accommodate CanStates Gas Marketing requirements in the 1990 contract year. Power City intends to use this gas supply to fuel a proposed cogeneration facility which it proposes to construct in the Massena, N.Y. area.

Power City's requirements were previously examined in GH-1-89 and GH-3-90 and resulted in the issuance of export Licence No. GL-144. TransCanada received authorization to build facilities to provide for Power City capacity. Husky, on behalf of Power City, received the export licence. Power City has targeted August 1992 as the date it expects its cogeneration plant to begin operations (GH-3-90). Any remaining regulatory authorizations are expected early in 1991, which would provide Power City with ample time to begin its contracted transportation service from TransCanada by 1 November 1992.

20.3.3 Other Service Requests Not Included in TransCanada's Facilities Application

TransCanada received many new domestic and export requests for service for the 1991/92 contract year, over and above those included in its requirements forecast. These additional requests were identified in TransCanada's queues for 1991/92 transportation service and amounted to 36 288 $10^3m^3/d$ (1 280 MMcfd). TransCanada also referred to the extensive number of new requests for service in the 1992/93 contract year as an additional indicator that demand for firm service exists, and that the existence of such factors supports the requirements forecast presented by TransCanada.

20.4 Views of Parties

Interested parties commented on the overall requirements forecast.

Despite the current state of the North American economy, the contractual arrangements underpinning the applied-for facilities and the extensive queue, ICG Ontario believed that TransCanada's forecast of requirements for

domestic and export sales and transportation was reasonable.

IPAC believed that the evidence established the existence of a strong market for Canadian gas in the U.S. Northeast, as supported by various producers, marketers, U.S. buyers and regulators in their collective endeavour to attach additional U.S. Northeast markets for Canadian gas. IPAC believed TransCanada's requirements forecast was reasonable and recommended that all of the applied-for facilities be certificated as soon as possible.

IPAC submitted that the TransCanada 1991/92 FAQ shows that sufficient requirements exist to ensure that the proposed facilities will be fully utilized. IPAC also referred the Board to TransCanada's all other firm service queues which list an additional 51 10^6m^3/d (1.8 Bcf/d) of requested transportation service requirements from prospective shippers who were unable to gain entry into TransCanada's 1989/90, 1990/91 and 1991/92 FAQs. IPAC urged the Board to also look at the 1992/93 queues for service which indicate a further 36.8 10^6m^3/d (1.3 Bcf/d) of service requests. While IPAC did not suggest that all, or even most, of these contemplated transportation services will materialize, it submitted that their existence clearly demonstrated an overwhelming demand for firm capacity.

PanCanadian Petroleum Limited ("Pan Canadian") viewed the substantial queue for service on the TransCanada system as evidence of the need to authorize the construction of the applied-for facilities.

Union did not view the length of the existing queues as evidence having any bearing on the question of whether the applied-for facilities would be used and useful five years hence. Union believed that, although queue length does imply the current magnitude of the demand for transportation service on TransCanada's system, it should not be used to argue that the facilities will necessarily be fully utilized in the future. Union argued that the current queue length misconceives the nature of the risk of under-utilization of facilities in the future.

The existence of the extensive requests for service currently underlying the facilities sought in TransCanada's application; and the existence of requests for service for future contract years and presumably underpinning a future facilities application for volumes of approximately 9.632 10^6m^3/d (340 MMcfd), lead the APMC to view the TransCanada forecast of requirements for domestic and export and sales transportation as being reasonable. In its view, these requests for service, coupled with the overall market demand for gas in the U.S. Northeast form a sound basis for the Board to approve the facilities applied for.

Indeck also referred to the real demand for transportation service on TransCanada's system in referring to the 1991/92 and 1992/93 queue lists of parties who have signed FS (precedent) agreements and are included in the 1991/92 facilities application.

With respect to the FSC-Plattsburgh project, both Consumers' and Union believed that it should not be certificated. Both submitted that it would be premature to issue a certificate for the pipeline capacity associated with this project because TransCanada and FSC had failed to demonstrate that the necessary contractual and regulatory approvals associated with the downstream arrangements would be in place in a timely manner. Both also believed that the related regulatory approvals and the financial and construction arrangements associated with FSC-Plattsburgh cogeneration projects were not sufficiently advanced.

For example, Consumers' noted the need for approval of an Environmental Impact Statement and the issuance of a Permit to Construct and Certificate to Operate prior to May 1991. Consumers' was also skeptical about the reasonableness of the timing for the construction of the connecting North County pipeline and for the receipt of the state and federal authorizations needed prior to its construction. Consumers' was also concerned about FSC's steam hosts arrangements and their being able to maintain their QF status in the absence of executed thermal energy contracts for the purposes of the requirements of the Public Utilities Regulatory Policies Act of 1978 ("PURPA") legislation.

In addition to the reasons cited by Consumers', Union, too, believed that the FSC-Plattsburgh project should provide evidence indicating binding assurance of takes, and in the absence of such

assurance, recommended that the Board deny certification of the related TransCanada pipeline facilities. Union believed that if the project's shipper fails to commit to take the gas, it would be unfair and inequitable for the remaining system shippers to pay for a portion of the facility costs associated with this export project.

With respect to the new licence applications supporting the expansion, Consumers' opposed the projects of Brymore/Pawtucket and Indeck-Corinth for both licence and certificate purposes. The basis for Consumers' opposition is set out in Chapters 3 and 9 respectively. Similarly, Union opposed the projects of Brymore/Pawtucket, New England Power, and WGML/Elizabethtown. The basis for Union's opposition is set out in Chapters 3, 14 and 17 respectively.

20.5 Views of the Board

The Board finds TransCanada's forecast export requirements to be reasonable for the purposes of assessing facilities requirements for the 1991/92 and 1992/93 contract year.

In order to ensure that the applied-for facilities are used and useful, the commencement of construction of the approved facilities will be conditioned upon TransCanada demonstrating, to the Board's satisfaction that, in respect of new firm export volumes, all necessary U.S. and Canadian federal regulatory approvals have been received. In addition, TransCanada will be required to demonstrate that, with respect to the transportation of all new firm volumes on its system, all necessary U.S. and Canadian regulatory approvals have been granted in respect of any necessary downstream facilities or transportation services. These necessary approvals include those required for the construction of facilities and the necessary implementation of incremental services on the Great Lakes, Union, Iroquois and Empire systems.

Should any of the individual shippers identified in TransCanada's forecast of export deliveries be unable to meet their scheduled commencement dates, with the consequence of a cancelled or delayed export project, the Board expects TransCanada to substitute sufficient long-term contracted FS requirements in time to replace such projects.

The Board, however, shares the concerns expressed by certain parties that service request substitutions may result in a portion of the GH-5-89 expansion being constructed without public scrutiny of the associated service requests. This would happen if the service request of a shipper examined in the GH-5-89 proceedings did not come to fruition and if TransCanada replaced it with a domestic service request or an export proposal considered in a separate Part VI proceeding. Recent experience indicates that the scope and magnitude of substitution in previously certificated expansions has been limited. However, should this change, the Board would consider seeking the views of interested parties regarding the extent to which a substituted service request supports TransCanada's request that commencement of construction be permitted pursuant to the certificate. The exact scope of this procedure would be determined on the basis of the particular circumstances before the Board at that time.

Chapter 21
Contractual Arrangements and Risk Allocation

21.1 Introduction

The current issue of whether the contractual arrangements supporting the proposed facilities appropriately allocate risk between TransCanada and prospective shippers had its origin in the GH-2-87 proceedings, where the degree of contractual and regulatory risk associated with the ANE Project and how that risk was to be allocated among parties to the ANE Project was considered. Specifically, that issue focussed on the liability for payment of TransCanada's transportation charges with respect to the ANE export volumes.

In the current proceedings, parties examined the question of the enforceability of the assignment provisions contained in the gas purchase and gas sales agreements and the enforceability of the assignment provisions contained in the related financial assurance arrangements. The assignment provisions are more fully described in the Board's Reasons for Decision, GH-2-87, pages 17 and 18. In brief, the intent of the various types of assignment provisions is to assign to TransCanada all the rights and privileges as if it had contracted directly with the U.S. repurchasers. Parties also examined the scope of the various force majeure clauses in the associated gas purchase and gas sales agreements. In particular, parties examined whether a revocation by a government or a regulatory agency or a denial, in whole or in part, of the pass-through of any of the purchasers' costs by a state commission in exercising its retail rate-making authority, would be an event of force majeure as contemplated by the parties to these agreements and if so defined, would relieve the U.S. repurchasers of their obligation to pay demand charges.

The Board asked parties, in the GH-5-89 proceedings, to address:

> *"The question of whether the contractual arrangements associated with those new services supporting TransCanada's applied-for facilities appropriately allocate risk between TransCanada and prospective shippers."*
>
> (Issue III-15)

During the hearing, in addition to regulatory risk, parties also raised concerns with respect to the use of financial assurances to protect existing shippers from having to absorb unrecovered demand charges that might occur as a result of new shippers accessing the TransCanada system, and regarding the allocation of unrecovered demand charges.

In a very broad sense, the issue invited parties to address the following:

(i) State Regulatory Action and Force Majeure
(ii) Financial Assurances
(iii) Allocation of Unrecovered Demand Charges

21.2 State Regulatory Action and Force Majeure

TransCanada believed the two concerns relating to contracts and financial assurances, identified by the Board in its GH-2-87 Reasons for Decision, have been resolved.

The first concern related to the enforceability of rights assigned to TransCanada respecting the contractual arrangements between ANE and its suppliers and ANE and its U.S. Repurchasers. TransCanada viewed its execution of Consents and Agreements by both parties to the assignment, as confirmation of the assignment of rights and grant of associated rights. It believed that direct contractual privity had been made between all parties to each underlying contract in which rights were being assigned and between the parties to which the rights were being assigned.

The second concern related to the interpretation of force majeure under the Gas Purchase Contracts and Gas Sales Agreements (financial assurance arrangements) entered into by TransCanada in connection with its transportation of the ProGas and ATCOR volumes sold to ANE. TransCanada believed that this concern was resolved by its execution of the principles of settlement agreements between ANE and each of its gas suppliers in which the U.S. Repurchasers agreed to the conditions under which a claim of force majeure would exempt them from paying TransCanada's transportation demand charges, namely:

(i) TransCanada's inability to deliver gas to the U.S.-Canada border point, and

(ii) a governmental order that would interrupt deliveries or prevent the export, import, or ANE's resale of the gas.

In addition, ANE and each of its gas suppliers agreed that:

> *"An order of a state regulatory agency preventing a U.S. Repurchaser from passing through in its retail rates all or any portion of the demand charges incurred under the (Gas Purchase) Contract shall not relieve that U.S. Repurchaser of its obligation to pay such demand charges."*

TransCanada believed this provision, along with the existing force majeure clauses under the gas sales agreements (which already stated that a lack of finances by the U.S. repurchasers would not constitute an event of force majeure) obligated the U.S. repurchasers to pay TransCanada's transportation demand charges.

ANE agreed with TransCanada's position and submitted that a number of changes have occurred since the release of the GH-2-87 Reasons for Decision which go as far as is practical towards addressing the Board's concerns. These include clarifications contained in the principles of agreement, diminished risk because of recent regulatory rulings, and the existence of financial assurance packages.

The principles of agreement entered into by ANE and the four ANE Project shippers set out the two circumstances of force majeure under which ANE and its U.S. repurchasers would be relieved of demand charge obligations.

The principles of agreement provide, as a corollary, that an order of a state regulatory agency preventing a U.S. Repurchaser from passing through, in its retail rates, all or any portion of the demand charges incurred under the gas purchase agreements does not release that U.S. repurchaser of its obligation to pay those demand charges.

The gas sales agreements between ANE and the ANE Project shippers and between ANE and each of the U.S. repurchasers all have force majeure clauses. The clarification of the applicability of the force majeure clause was intended to apply to the agreements and the U.S. repurchasers' consent was sought, since they were not parties to the principles of agreement and there was no intention to enter into a similar principles of agreement with them.

ANE's view was that a state regulatory order preventing the U.S. repurchaser from passing through any or all of its demand charges in its retail rates was a regulatory risk, not an event of force majeure. ANE testified that Clause 4 of the principles of agreement had been interpreted so as to not allow a claim of force majeure in the event of a state order prohibiting the pass-through of the demand charges.

ANE argued that the risk of a claim of force majeure occurring is minimal in view of the fact that various regulators at both the federal and state levels have endorsed the ANE/Iroquois export project and the associated contracts. ANE noted that TransCanada had expressed its satisfaction with the various contracts and the associated financial assurance arrangements. In addition, ANE submitted that it and the gas suppliers have agreed that such an event would not relieve the U.S. repurchasers of their obligation to pay demand charges and ANE would sue to enforce that obligation.

IPAC had no concerns with shippers being exposed to the risk of having to absorb unrecovered demand charges as a result of TransCanada's inability to enforce the contractual

rights assigned to it under the gas purchase and sales agreements, and the financial arrangements between ANE and its four suppliers and its U.S. repurchasers. The fact that ANE's repurchasers have not defined the specific circumstances of force majeure relieving a U.S. repurchaser of its obligation to pay demand charges is not something that TransCanada has control over. IPAC argued that the U.S. repurchasers are not the shippers of record on TransCanada's system; the Canadian suppliers are. ANE's Canadian shippers have each entered into separate principles of agreement with ANE, in a direct attempt to alleviate the concerns of the Board expressed in its Reasons for Decision in GH-2-87. IPAC agreed with TransCanada's comments on these principles of agreement, and believed that TransCanada had done all it could to satisfy itself that there was a contractual obligation for demand charges to be paid throughout the full term of the contracts.

Consumers' expressed concern with the ANE repurchasers declining to exclude state regulatory action, denying the passthrough of demand charges, from the definition of "force majeure" in their gas sales contracts with ANE. Although Consumers' acknowledged TransCanada's position that such a risk materializing was small, it was, nevertheless, a realizable one. Consumers' argued that for the purposes of future toll-making, the Board should make a prudency finding now that would inform TransCanada that if the risk of unrecovered demand charges due to a successful force majeure claim materialized, the resulting unrecovered demand charges would be on the account of TransCanada, not on the account of its tollpayers.

21.3 Financial Assurances

TransCanada stated that the purpose of obtaining financial assurances from prospective shippers is to protect existing shippers from having to absorb any unrecovered demand charges that may occur as a result of new shippers accessing the TransCanada system and, at some time during the term of their transportation service contract, not being able to pay the monthly transportation charges.

One of the conditions new shippers must satisfy in their precedent agreements with TransCanada, in order to be considered for inclusion in a facilities application, is to agree to provide financial assurances satisfactory to TransCanada. The fulfillment of such a condition is necessary prior to TransCanada executing a FS contract with the shipper.

In addition, TransCanada stated that financial assurances are a means of protecting TransCanada's shareholders by demonstrating the exercise of financial prudency in contracting with new shippers, and thus limiting its shareholders' exposure to the risk of having to absorb unrecovered demand charges.

TransCanada stated that the requirement for financial assurances has the effect of transferring some of the contractual and regulatory risk for the construction and utilization of new facilities, from existing shippers and shareholders, to the new shippers.

TransCanada maintained that the best form of financial protection for existing shippers from the possibility of having to absorb unrecovered demand charges, is the length of time that a new shipper would be liable for payment of its demand charges under a FS transportation contract. TransCanada believed that, ideally, this protection ought to cover the entire term of the FS contract. However, because of the magnitude of the demand charges, a practical level was determined to be one year, so as not to exclude smaller shippers access to the system. TransCanada noted that the minimum financial assurance required for new capacity far exceeds the two months of demand charges and 60 days of commodity charges provided for in the tariff.

TransCanada submitted that, based on the financial assurances obtained, it had been as prudent as possible and should be allowed to recover any unrecovered demand charges.

21.4 Allocation of Unrecovered Demand Charges

The issue of the allocation of unrecovered demand charges was first raised by Consumers' in the context of the financial assurances obtained from new shippers in order for TransCanada to include them in its application for new facilities. Although Consumers' did not question TransCanada's determination of the creditworthiness of a potential shipper, it was

concerned with the allocation of unrecovered demand charges should a shipper prematurely leave the system at a time when no long queues for service existed.

Of particular interest was the term of coverage of the financial assurances relative to the length of the entire term of the new shipper's transportation contract. TransCanada explained the intent of financial assurances is best fulfilled if it covers the entire term of the new shipper's transportation contract. Consumers' endorsed this objective of financial assurances but was concerned about the adequacy of the letter of credit form of financial assurance which provides only one year of demand charge coverage, when a project of much longer duration was being proposed.

Consumers' was particularly concerned with the allocation of the risk of unrecovered demand charges that might result from the failure of this type of arrangement and believed the onus should be put on TransCanada to demonstrate that its financial assurance arrangement was prudent and that it should bear the risk of any unrecovered demand charges that might result. Although Consumers' recognized the existence of a revenue deferral account to record unrecovered demand charges, TransCanada should not assume that it would be automatically entitled to pass those charges on to the remaining system shippers through recovery in future tolls. Consumers' believed that the Board should put TransCanada on notice that it should be prepared to bear the risk of any unrecovered demand charges and that any balance that was allowed to be deferred would be disposed of in the context of a tolls proceeding, on the basis of a prudency review. In the case where imprudency of a financial assurance agreement was found, Consumers' submitted that the Board should inform TransCanada now that it would not automatically be entitled, in the context of some future tolls proceeding, to continue to pass on to the remaining shippers what would otherwise continue to be unrecovered demand charges.

Union was concerned with the risk associated with the type of financial assurances involving only one year of demand charge coverage. Union stated that TransCanada made the decision to construct facilities based on such financial assurances and any certificate that may be issued by the Board should not be taken as tacit approval of the prudency of TransCanada's decision. Union argued that TransCanada's shippers should be protected from any risks of under-utilization of facilities by the denial of recovery by TransCanada of unpaid demand charges in future tolls. In Union's view, shippers will be paying substantial increases in tolls as a result of this facilities expansion, and unless the new shippers are prepared to commit to take the gas for which the expansion is sought, then the facilities should not be constructed.

Union also addressed the issue of under-utilization of facilities in terms of whether shippers leave the system prematurely because of competitive pressures and avoid the TransCanada contractual obligations through regulatory "out" clauses or simple contract abrogation. Union expressed concern with the possible situation where demand charges are being paid, but underutilization of facilities arises from the failure of shippers to transport the gas for which they had contracted capacity, where that failure to take gas was the result of an economic decision of the project to get its gas elsewhere, to use an alternate fuel or to operate below forecasted levels.

In Union's view, two approaches could be taken by the Board to address these concerns. The first approach would be to certificate the facilities, but to ensure, by imposing the risk of underutilization of facilities on TransCanada, that TransCanada would have an incentive to examine its targeted market and to take account of the presence of competition in future tolls. Union suggested that the Board could put TransCanada on notice that certification of the GH-5-89 facilities does not insulate the recovery of their cost from risk allocation treatment in the future.

The second approach would be for the Board to take account of the risk of underutilization of facilities in the certification process itself. To the extent the Board imposed the required incentive and discipline on TransCanada by certificating only a portion of the applied-for facilities and leaving the decision to TransCanada to select, for its application queue, the projects which presented it with the lowest risk of underutilization of facilities. Union, while not rejecting such an approach, does not consider it appropriate to take a position on it without

hearing evidence as to how TransCanada would apply such an approach to the facilities applied-for in this hearing.

The approach preferred by Union is for the Board to examine carefully and critically each project underlying the facilities application, eliminating projects which have a high risk of underutilization from certification. In Union's view, the Board cannot take any assurance that if some of the projects underlying the facilities application do not prosper, or are not renewed after the expiry of the term of their contracts with TransCanada, the resulting capacity will be used to serve other customers.

On the other hand, IPAC believed TransCanada has prudently negotiated the various financial assurance contracts with the project sponsors underpinning its proposed facilities expansion, and that these various forms of financial instruments demonstrate TransCanada's concern that existing shippers not be exposed to unabsorbed demand charges.

IPAC fully agreed with TransCanada's reasons for the purpose, content, extent, and policy of financial assurances designed to protect existing shippers from unrecovered demand charges and to protect its shareholders. IPAC cautioned that financial assurances should be reasonable in the circumstances and balanced with an individual shipper's ability to provide such assurances, and believed that the letter of credit form of financial assurance does achieve such a balance.

GMi believed that the Board should continue to be governed by its Reasons for Decision respecting the allocation of risk set out on page 26 of GH-2-87 that the contracts underpinning the ANE Project may not, in certain circumstances, be enforceable with respect to the collection of unpaid demand charges, and that TransCanada, by proceeding with the system expansion, will be considered to have accepted the fixed-cost risk for its own account and not for the account of the tollpayers. In GMi's view, TransCanada is aware of the risk inherent in the project. Accordingly, any facilities that become no longer used and useful as a result of this risk materializing, should be subject to review in a future TransCanada toll proceeding.

The APMC believed that existing tollpayers on the system should not be required to absorb any of the costs of shippers failing to live up to their contractual obligations to pay demand charges, and that an appropriate degree of financial assurance to shield existing tollpayers from this potential risk is warranted.

21.5 Views of the Board

The Board agrees with Consumers' and Union that TransCanada, as the proponent of the facilities applied-for, is in the best position to determine the extent of the risk of unrecovered demand charges at the time it negotiates its financial assurance agreements with the proponents of the projects included in its facilities applications and to assess the ripeness of the projects.

The Board shares the views of TransCanada that one purpose of contractual arrangements and financial assurances is to allocate risk so that existing tollpayers will not be asked to absorb costs arising from any shipper failing to live up to its contractual obligations to pay demand charges. TransCanada's requirement for satisfactory contractual and financial assurance arrangements is one of the many steps it takes in determining the viability and the maturity of a shipper's project.

In taking such steps, TransCanada determines the creditworthiness of a new shipper and assesses the degree of risk of that shipper being able to meet its financial obligations over the term of its contract. These are contractual arrangements between two parties, with affected parties having recourse to the Board if they believe TransCanada has unfairly exercised its monopoly power.

In this proceeding, the Board heard no evidence nor received any complaints of unjust discrimination by TransCanada in having prospective shippers meet these requirements. The decision as to what type of particular financial assurance agreements apply in a particular case, requires the exercise of informed judgement on the part of TransCanada. In the event that demand charges remain unrecovered in the future as a result of the failure of a particular financial assurance agreement, then the question of prudency of that particular agreement would be

subject to normal review in a future tolls proceeding. At that time, TransCanada would be expected to demonstrate that its selection of a particular type and quality of financial assurance had been prudent.

As indicated in the Board's Reasons for Decision with respect to tolling and economic feasibility related to this pipeline expansion (GH-5-89 Reasons for Decision, November 1990, Volume 1, p. 36):

> *If the risk of under-utilization should materialize and result in unrecovered demand charges, these will accumulate in the deferral account and be brought forward for disposition in a toll proceeding. The Board will then examine closely the circumstances which led to the under-recovery and determine what portion, if any, should be recovered from shippers. On the other hand, as has often occurred in the recent past, if an over-recovery of demand charges results from unanticipated shippers coming on the system, the Board will consider those circumstances as well to determine what portion, if any, of the excess revenue should be passed on to shippers. Therefore, TransCanada can be said to be exposed to some risk.*

In argument, Consumers' proposed that the Board establish at this time that unrecovered demand charges stemming from a claim of force majeure in the gas sales agreements between ANE and its repurchasers, as a result of an adverse U.S. state regulatory action with respect to demand charge pass-through, would be for the account of TransCanada and not for the account of tollpayers. The Board is not persuaded that it should attempt to determine, in advance, the precise toll treatment applicable to future unrecovered demand charges, without full details of the facts which gave rise to the situation. Any unrecovered demand charges authorized to be recorded in a deferral account should be brought forward for disposition in a subsequent toll proceeding.

In this regard, the Board is aware of TransCanada's assertion in argument that it should be allowed to recover any unrecovered demand charges. The Board does not share this view. In considering the disposition of deferred balances, it is the Board's view that the onus is on TransCanada to demonstrate that its actions were prudently taken in the interests of its tollpayers.

Chapter 22
Facilities

22.1 Facilities Design

TransCanada's total expansion proposed in GH-5-89 would provide the additional system capacity which, when combined with existing and previously authorized facilities and those included in the Blackhorse section 58 application which is currently being considered by the Board, would serve existing gas markets and 23.56 $10^3m^3/d$ (831.5 MMcfd) of new firm domestic and export transportation requirements. It would also allow for the retirement of three aging compressor units.

The original 29 June 1989 application included an expansion of the Great Lakes system and TransCanada's Montreal Line to provide most of the additional transportation capacity from Winnipeg to eastern Canada. For various reasons, discussed in section 22.4, TransCanada amended its application in December 1989 to provide for expansion of the northern Ontario route via the Central Section and the North Bay Shortcut.

As explained in section 22.3, TransCanada received early authorizations in 1990 for three new compressor units, two unit relocations, and 396 km of looping to provide 4.4 $10^6m^3/d$ (155 MMcfd) of FS and about 1 $10^6m^3/d$ (35 MMcfd) of storage transportation service. The remaining facilities for which TransCanada is requesting authorization consist of 1190 km of looping and 17 compressor units (225 MW) to transport 19.2 $10^6m^3/d$ (677 MMcfd) of new firm service, primarily to export points in eastern Canada. The capital cost of these remaining facilities is estimated at $1 835 million, as summarized in Table 22-1, and the revised cost of the total GH-5-89 expansion is estimated at $2 408 million. The details of the proposal for individual segments of the system are described in section 22.2. A map of the remaining facilities appears as Figure 22.1.

The design of the facilities is generally based upon TransCanada's studies of the present worth of annual owning and operating costs over a 28 -year period. Certain modifications to this methodology were used for the Western Section, where practical considerations resulted in an increased compression alternative, and for the Great Lakes flow split where a 10-year present worth analysis and certain qualitative factors were also considered.

The magnitude of the total 1991 and 1992 construction program led to a considerable amount of evidence regarding the timing of construction, the lead times required for compressor deliveries, and the in-service dates for various levels of additional capacity. TransCanada stated that only 6.2 $10^6m^3/d$ (220 MMcfd) of GH-1-89 system-wide capacity is available as of November 1990, and this will increase to the full 14.7 $10^6m^3/d$ (520 MMcfd) for November 1991 after the completion of Western compression additions and the required Great Lakes facilities build-up.

Additional new capacity of 6.3 $10^6m^3/d$ (222 MMcfd) will be available in November 1991, primarily due to the facilities authorized by the Partial Facilities Certificate. It is forecast to increase steadily over the next year to the full amount of 23.5 $10^6m^3/d$ (831 MMcfd) proposed in the GH-5-89 proceeding by November 1992. This would depend upon the extent to which transportation contracts are executed and the time needed to complete looping and compression projects.

Views of Interested Parties

Most interested parties provided support for the overall design of facilities proposed by TransCanada to serve forecast market requirements, except as noted in section 22.6.

However, Consumers' and Union did express concerns with certain new service requests, as indicated below, on the basis of their ripeness, inadequate supply, or lack of binding assurances of takes.

Table 22-1

Summary and Estimated Cost of Proposed Facilities

			Total Estimated Capital Cost ($MM, 1989)
1991 Pipeline Construction			
Western Section 1219 mm Loop	Saskatchewan	190.5 km	201.1
	Manitoba	100.9 km	104.5
Central Section 1067 mm Loop	Manitoba	54.1 km	65.1
	Northern Ont.	558.5 km	720.4
North Bay Shortcut 1067 km Loop	Ontario	123.2 km	177.9
1992 Pipeline Construction			
Western Section 1219 mm Loop	Saskatchewan	58.1 km	57.9
	Manitoba	34.0 km	42.3
Central Section 1067 mm Loop	Northern Ont.	11.3 km	14.5
North Bay Shortcut 1067 mm Loop	Ontario	59.2 km	79.5
Total Pipeline		1189.8	1463.4
Compression and Metering			
Western Section Three 26.1 MW Units, Stations 2, 25, 34			67.4
Central Section Seven 9.4 MW Units, Stations 43, 52, 60, 62 77, 84, 102			114.6
One 14 MW Unit, Station 55			19.0
North Bay Shortcut/Montreal Line Two 14 MW Units, Stations 1206, 1211			37.9
One 4.1 MW Unit, Station 147			7.7
Iroquois Extension Two 14 MW Units, new Station 1401			39.1
Iroquois Meter Station			3.8
Kirkwall Line One 6.3 MW Unit, Station 1301			11.2
Other Facilities Station Manifolding, Standby Plant, Spares, Station 1401 Aftercooler			71.1
Total Compression and Metering			371.7
TOTAL 1991 AND 1992 EXPANSION			1 835.1

	$10^3m^3/d$	MMcfd
Consumers'		
Indeck Corinth	496	(18)
FSC Plattsburgh/Welch	1 263	(44)
Pawtucket	360	(13)
Total:	2 119	(75)
Union		
FSC Plattsburgh/Welch	1 263	(44)
Pawtucket	360	(13)
New England Power	1 700	(60)
WGML/Elizabethtown	283	(10)
Total:	3 606	(127)

Consumers' and Union argued against the issuance of Part VI licences for these applications, and also argued against certification of the facilities that would be required to accommodate those volumes.

Views of the Board

The Board considers that the proposed facilities represent an appropriate design for an expansion of the TransCanada system to provide the new firm transportation requirements for the 1991/92 and 1992/93 contract years. The cost of these facilities, when combined with those of the Partial Facilities, is representative of the long-term average capital cost of expansion on the TransCanada system. This is approximately \$100 million per $10^6m^3/d$ (\$3 million per MMcfd) for firm transportation capacity from Empress to the middle of the Eastern Zone. The Board notes that interested parties did not express significant concerns with the overall design of the TransCanada proposal. The Board therefore is prepared to accept the proposed design of these new facilities.

The arguments by Union and Consumers' to the effect that the Board should certificate less than the applied-for facilities are addressed in Chapter 25.

22.2 Specific Facilities

22.2.1 Western Section

The facilities on TransCanada's Western Section which are the subject of this application consist of 384.6 km of 1 219 mm looping in Manitoba and Saskatchewan, and three 26 MW compressor units at Stations 2, 25 and 34. TransCanada's estimated cost for these facilities is \$473.6 million. Three-quarters of this looping is planned for construction in the summer of 1991, while the remaining loop and the compressor units are scheduled for completion in the fall of 1992.

TransCanada's design of the Western Section is based upon meeting winter seasonal requirements. When combined with the 111.7 km of looping of the Partial Facilities authorized by Certificate GC-78, the expansion would allow for an average increase in net throughput capability of about 18 percent, from 22 000 10^6m^3 (777 Bcf) in the 1990/91 winter to 25 940 10^6m^3 (916 Bcf) during the 1992/93 winter season. This would correspond to an increase in average day input capacity at the Empress receipt point from approximately 144 $10^6m^3/d$ (5.1 Bcf/d) to 165 $10^6m^3/d$ (5.8 Bcf/d), with some further additional capacity installed downstream of various Saskatchewan receipt points. A small portion of the proposed facilities would also allow for the retirement of the last of three old 7 MW Clark compressors.

The 19 loop sections proposed would complete the fifth Western line and would result in over one-third of Line 100-6 being installed by the end of 1992. TransCanada presented several alternative designs with various combinations of loop and compression. It concluded that while a more loop-intensive design combined with one compressor unit had the lowest estimated long term present worth, the three-unit design chosen has a lower capital cost and certain operational advantages. TransCanada also stated that the use of 1422 mm diameter pipe, and the upgrade of several Avon gas turbines, were not appropriate design alternatives.

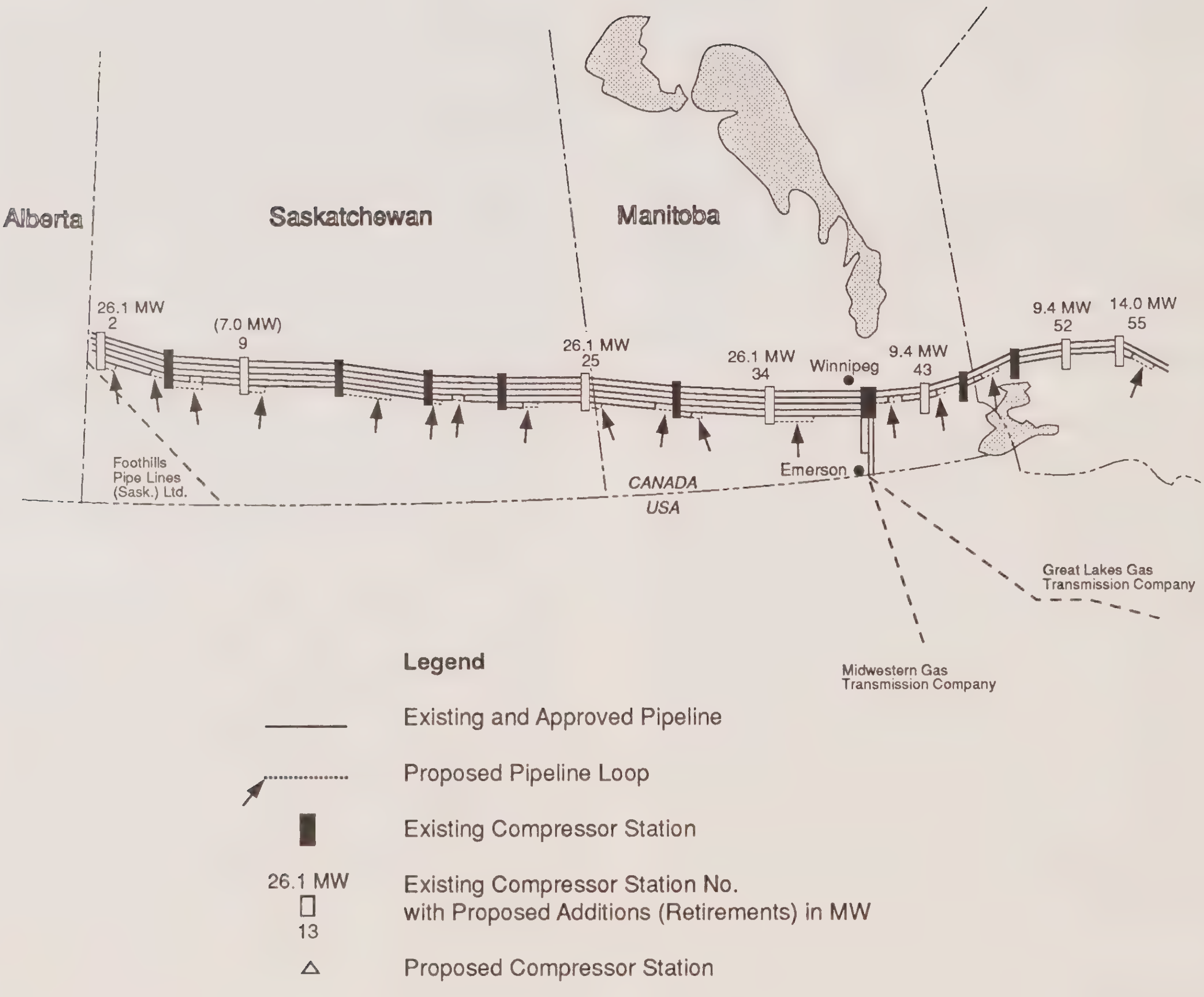

Alberta
Saskatchewan
Manitoba
26.1 MW
2
(7.0 MW)
9
26.1 MW
25
26.1 MW
34
Winnipeg
9.4 MW
43
9.4 MW
52
14.0 MW
55
Foothills
Pipe Lines
(Sask.) Ltd.
CANADA
USA
Emerson
Great Lakes Gas
Transmission Company
Midwestern Gas
Transmission Company
Legend
Existing and Approved Pipeline
Proposed Pipeline Loop
Existing Compressor Station
26.1 MW
13
Existing Compressor Station No.
with Proposed Additions (Retirements) in MW
Proposed Compressor Station

Figure 22.1

TransCanada PipeLines Limited

Location of Applied-for Facilities

The original application had included a design with three 14 MW compressor units, for a total cost of $60 million. Subsequent to a Board information request, TransCanada studied the option of installing larger compressor units and decided that it was preferable to choose the larger 26 MW units, at a cost of $67 million. These 26 MW units would result in significant long-term fuel savings, increased system reliability and would allow every Western compressor station to have at least one large, modern unit.

22.2.2 *Central Section*

Over one-half of the proposed expansion is concentrated on the Central Section, as a result of TransCanada's decision to move all of the incremental throughput through Northern Ontario (see Section 22.4). The proposed facilities consist of 623.9 km of 1 067 mm looping and the installation of eight new compressor units at a total capital cost of $931 million. These are in addition to the 272 km of loop and two portable unit relocations approved by the partial certificate decision of November 1990 (GH-5-89 Reasons for Decision, Volume 2), and two compressor units exempted from certification pursuant to section 58 of the Act.

The proposed expansion, combined with the Partial Facilities, would increase the annual throughput capability of the Central Section from the existing level of about 22 350 $10^6 m^3$ (789 Bcf) to 30 500 $10^6 m^3$ (1077 Bcf) in the contract year 1992/93. This capacity increase will be gradual, as construction will be phased-in over winter and summer periods during 1991 and 1992. Although the originally filed schedule called for almost all of the loop to be ready by the end of 1991, as shown in Table 22-1, updated evidence provided by TransCanada indicated the following forecast in-service dates for the total 1991 and 1992 Central Section expansion.

	Looping	Compressor Stations
1991		
Jan - Apr	224 km	
May - Dec	274 km	Portables (43,62)
1992		
Jan - Apr	291 km	60, 88, 102, 112
May - Dec	107 km	55,77,84,43,52,62

The proposed project, involving 39 loop sections, would leave only about 16 percent of the Central Section between Stations 41 and 116 unlooped by Line 100-3. It will therefore, also enhance the security of supply through this route by minimizing the possible impact of problems stemming from stress corrosion cracking associated with some portions of Line 100-2. The expansion will allow for the completion of the looping along the Thunder Bay Bypass, which is located in a remote area where repairs are difficult to complete. Construction during 1991 will also include an 8.5 km portion of loop in this area previously authorized by the Board's GH-1-89 decision of December 1989.

Present worth studies indicated that medium-sized compressor units were the best choice for the Central Section expansion. The compressor additions which are the subject of this application include seven 9.4 MW industrial-type gas turbines. Although TransCanada has traditionally purchased aero-derivative units for its mainline additions, the industrial units are practically the only type commercially available in this size range. TransCanada has indicated that their fuel efficiency and reliability are expected to be similar to aero-derivative units. Two of these units, at Stations 43 and 62, will be installed as permanent replacements for portable units, authorized by the Partial Facilities Certificate to make up for delays in receiving new compressor units.

The authorization, pursuant to a section 58 order issued on 1 June 1990, to install a 14 MW unit at North Bay (Station 116) has had to be amended. Operational problems with an existing unit here have necessitated its retirement, and the proposed

installation of a 26 MW unit at this location. On 4 February 1991 the Board issued an amending order to transfer the 14 MW unit to Station 88.

On 21 February 1991, TransCanada submitted an additional section 58 application for the installation of the 26 MW unit at Station 116, so that construction could begin in March, for completion by November 1991. In order to prevent a delay in completing the installation of this important compressor unit, the Board approved the application on 15 March 1991.

The two remaining old Orenda compressor units on the Central Section, at Stations 107 and 112, will be retired. However, since the installation of large new units at these stations, authorized in 1988 by Certificate GC-74, these retirements do not require their replacement with new facilities as part of the GH-5-89 application.

22.2.3 North Bay Shortcut/Montreal Line

TransCanada's decision to expand the Central Section to move the full incremental volume resulted in the selection of the North Bay Shortcut as the downstream route for the expansion in the Eastern Zone, instead of the Montreal Line. A primary factor here is the shorter distance involved in moving gas to the Iroquois export point, where most of the incremental throughput is destined. The North Bay Shortcut also has an advantage of initial cheap expansibility through compression additions.

The proposal includes installing two additional 14 MW units, one at Station 1206 and one at 1211, to complete the construction of the three new twin-unit compressor stations on the North Bay Shortcut by the end of 1992. The first two units were approved for the 1990/91 expansion by Certificate GC-77, issued pursuant to GH-1-89, and the second two were approved, during the GH-5-89 proceeding as part of the June 1990 section 58 authorization ($42 million). A total of 182.4 km of 1067 mm looping is also required on the North Bay Shortcut, as well as a third 4.1 MW compressor unit on the Montreal Line at Station 147 near Cornwall, Ontario. The total cost of the facilities for which approval to construct is still sought in this application is $303 million.

The facilities proposed in the combined GH-5-89 proceeding will increase the winter peak day capability of the North Bay Shortcut/Montreal Line system from a 1990/91 level of about 47 $10^6 m^3$/d (1.65 Bcf/d) to 65 $10^6 m^3$/d (2.3 Bcf/d). This system is also designed for loss of unit protection, and $43 million of the total expenditure is needed to provide for this security.

22.2.4 Iroquois Extension

TransCanada proposes to install two 14 MW units on the previously authorized Iroquois Extension at a new Compressor Station 1401. One unit is scheduled for construction during the summer and fall of 1991, while the second is forecast to be built during the summer of 1992. One will operate on a stand-by basis to provide loss of unit protection. In this configuration, the Extension will have an export capacity of about 18.4 $10^6 m^3$/d (650 MMcfd).

The Iroquois Extension will be somewhat unusual on the TransCanada system since the Iroquois Gas Transmission System will have a maximum operating pressure of 9930 kPa, compared to the 6450 kPa level on the Montreal Line. As the only initial source of compression for the system, Station 1401 will need an aerial aftercooler to accommodate the relatively high compression ratio. A new export meter station will also be constructed.

The total cost of these compression and metering facilities is estimated at $48 million. Since most of the cost of these facilities is attributable to the delivery of pressure in excess of 4000 kPa, a delivery pressure charge of about 4 cents/GJ, including fuel, will be levied on Iroquois shippers.

22.2.5 Kirkwall/Niagara Line

TransCanada has applied in a separate section 58 application for the Blackhorse extension to construct a new 6.3 MW compressor Station 1301 at Kirkwall Junction, to increase the capacity for exports through a proposed new lateral to Chippawa. This application is currently under review by the Board. In the GH-5-89 proceeding TransCanada proposed to install a second 6.3 MW unit at Kirkwall Junction during 1992, at a cost of $11 million.

This second compressor would accommodate the increase of 3.0 $10^6 m^3/d$ (107 MMcfd) of proposed exports via the Kirkwall/Niagara system, and would result in a combined system peak day capability of about 40 $10^6 m^3/d$ (1.4 Bcf/d).

22.2.6 Views of the Board

The applied-for facilities in each segment of the TransCanada system will be required to meet the forecast market requirements. The Board supports TransCanada's decision to deviate from the usual present worth analysis for the Western Section to allow the installation of three large compressor units rather than medium-sized units.

As previously stated in the Reasons for Decision for the Partial Facilities Application, the Board remains concerned that most of the compressor units will not be ready for service until the end of 1992. It is noted that TransCanada proposed to order most of the units by January 1991. TransCanada is encouraged to anticipate, at an early stage, the firming up of new FS requests in order to purchase and install units in a timely manner, and to achieve a facilities build-up which is balanced as much as possible throughout the expansion period.

The Board will recommend to the Governor in Council that any certificate include, as usual, technical conditions pertaining to the submission of construction schedules, progress and cost reports, drawings and specifications. For welding and non-destructive procedures, the Board will continue to rely on the requirements of its *Onshore Pipeline Regulations* and the standards of the Canadian Standards Association.

22.3 Partial Facilities

On 31 August 1990, TransCanada requested that the Board consider issuing a partial facilities certificate decision to allow for winter construction to ensure November 1991 service for TransCanada's most assured requirements. On 3 October 1990, TransCanada submitted its Partial Facilities Certificate Evidence in support of its request to construct 396 km of system-wide pipeline looping and relocate two portable compressor units at a cost of $546 million. This was in addition to the three new compressor units previously approved in a section 58 authorization on 1 June 1990. The facilities would provide 103 MMcfd of firm service transportation required by specific domestic shippers and 52 MMcfd of advance capacity for 1 November 1991. The Partial Facilities Certificate Application was heard by the Board on 15 and 18 October and subsequently granted TransCanada's application on 15 November 1990. Detailed information regarding this portion of the hearing may be found in Volume 2 of the GH-5-89 Reasons for Decision.

22.4 Central Section/Great Lakes Flow Split

In its original 29 June 1989 application, TransCanada proposed to meet all of its new forecast requirements east of Station 41 by expanding the Great Lakes system instead of its own Central Section in Northern Ontario. Long-term present worth studies at that time indicated that a $1.3 billion expansion of the Great Lakes and Union system was the most economical alternative, relative to three other cases which included shared expansions over both routes. In particular, the Great Lakes expansion offered approximately a two percent cost advantage, based upon a 28-year present worth analysis.

The major change in the revised 15 December 1989 application was the choice of the Central Section route to move all of the incremental throughput. This was the result of subsequent studies undertaken by TransCanada based upon new information and assumptions, as summarized below:

(i) Based upon an August 1989 application by Great Lakes to FERC, the cost estimates for its Line 3 loop construction increased by over 20 percent compared to previous estimates.

(ii) That application, with seven units, was more compressor-intensive than the three-unit design chosen by TransCanada, and this increased the incremental fuel usage on the Great Lakes system.

(iii) The above factors increased the capital cost of the Great Lakes expansion to $1.45 billion, and resulted in higher fuel costs. The overall effect on present worth translated into a 0.2 percent cost

advantage for a Central Section versus a Great Lakes expansion.

(iv) The move towards completion of the third Northern Ontario line would minimize the impact of stress corrosion cracking problems associated with Line 100-2, and would also reduce the effects of throughput loss as a result of periodic hydrostatic retesting.

(v) As a result of delay in Great Lakes receiving approval to construct its \$500 million program in 1990 for the GH-1-89 expansion, TransCanada decided that it was easier to coordinate a timely expansion if only one company was involved rather than three. In addition, authorizations from only one regulatory agency would be required.

There were several other changes to financial and operational assumptions that very nearly offset each other, and had little effect on the economics of the decision.

In addition to the 28-year present worth analysis, TransCanada also conducted a similar study over a 10-year period, using other sensitivity cases with varying economic assumptions, in order to achieve a greater level of certainty in choosing the preferred alternative.

TransCanada also indicated that a major reason that the shorter Great Lakes route did not have a significant advantage was that it would require a commencement of the third Great Lakes line, which is less economically efficient than moving toward the completion of the third Northern Ontario line. Given the increased compression requirements, Great Lakes would not have been able to receive regulatory authorization and to construct facilities in time to provide the required new service prior to November 1992. TransCanada, therefore, decided that a \$1.5 billion expansion of its Central Section was a better overall choice, and the advantage increased when the cost estimate was subsequently reduced to a total of \$1.37 billion.

In final argument, TransCanada reiterated its view that the four case alternatives studied, and an additional one requested by the Board, demonstrated that the northern route was the best choice from both a quantitative and a qualitative perspective.

Views of Interested Parties

Parties generally did not oppose TransCanada's route selection. However, Union was concerned that the decision had been made prior to a full review during the hearing process. Union argued that the flow split could only change by a Board decision either to deny approval of the whole project, or to refuse the recovery of increased costs of TransCanada's Central Section expansion. Union was also concerned about the relative duration of the 15-year Great Lakes transportation contract, and the economic evaluation over a 28-year period. It submitted that TransCanada should be held accountable for a flow split decision made before the hearing took place, and also for its future ramifications. The APMC argued it is important for TransCanada to keep in mind the potential in future for using Great Lakes but supported the timely presentation by TransCanada of the relative flow split economics for review during the hearing process.

Views of the Board

The evidence in this case indicates that the long-term economics of transporting volumes via the Central Section rather than the Great Lakes system do not afford a significant advantage to either route. The differences in long-term present worth of total owning and operating costs seem to be less than two percent, and this is probably within the range of uncertainty of the various assumptions used in the analyses. The Board believes that, for the purposes of the GH-5-89 proceeding, qualitative factors such as timing of regulatory review and construction, outweigh the effect of any small economic advantage that one route has over the other. The Board notes that while the Central Section route is about 560 km (33 percent) longer than the Great Lakes route for moving gas to Dawn, Ontario, it is approximately equal for transporting volumes to Toronto, and is in fact 270 km (12 percent) shorter for gas reaching the Iroquois export point via the North Bay Shortcut. In the Board's view this may be a significant factor in the engineering and economic analysis, which has offset the benefits of easier construction and lower per unit costs along the Great Lakes system. The particular stage of

looping, whether it is commencement or completion of a loop section, and the associated capacity increase, is also an important consideration for the analysis.

Therefore, the Board is of the view that TransCanada's choice of expanding the Central Section in the GH-5-89 proceeding is a reasonable one. The Board continues to believe that the flow split decision is an important one in the design of the pipeline system, and will continue to review this matter in subsequent proceedings. Furthermore, TransCanada will also continue to be held accountable for the prudency of its decisions in this respect in future Part IV toll proceedings.

22.5 Advance Capacity

TransCanada did not initially include any provision for advance capacity in the GH-5-89 application. This was due to the magnitude of the 1991 and 1992 construction program, and the fact that construction of an additional 130 km of loop for 2.13 $10^6 m^3/d$ (75 MMcfd) of advance capacity would be impractical.

Views of Interested Parties

All parties supported TransCanada's position that no additional facilities for advance capacity be certificated as a result of this application. Union suggested that the Board continue to review the matter on a case-by-case basis. It went a step further in requesting that TransCanada include an allowance for advance capacity in each future expansion so that it could be reviewed in a timely manner by interested parties and the Board.

Certain parties, such as IPAC, APMC and L&J Energy Systems, Inc., submitted that some extra capacity could become available if the Board chose to deny some export licences. In that event, they argued, all of the proposed facilities should still be approved and the resulting available capacity allocated according to queuing procedures.

Views of the Board

The Board had no application for advance capacity before it in this final phase of the proceeding and sees no need to consider at this time additional facilities to provide for advance capacity, due to the magnitude of the 1991 and 1992 construction program and a possible further application by TransCanada for 1992/93 capacity. The need for advance capacity will continue to be reviewed on a case-by-case basis. The Board does not agree with Union's suggestion that TransCanada should include a provision for advance capacity in every expansion application.

22.6 Loss of Unit Protection

TransCanada did not include additional facilities in this application to provide loss of unit protection for its Western Section. Such a design would have required about $97 million of Western looping for 1991/92. In 1989, TransCanada had investigated the introduction of a new limited interruptible firm ("LIF") service to allow for a toll discount for service which could be periodically curtailed during unit outage situations on coincident winter peak days. Subsequent to the Board's denial of facilities for loss of unit protection in its GH-1-89 decision, there were several meetings of an industry task force to discuss the proposed new LIF service. The conclusion reached at these meetings was that the service did not appear attractive to most shippers.

During the GH-5-89 proceeding, TransCanada stated that it would investigate two alternatives for providing loss of unit protection, Western looping facilities or downstream storage services. The use of downstream underground storage initially appeared to be the most economical option. However, near the end of the hearing, TransCanada indicated that the lack of firm Great Lakes transportation capacity to storage would make looping facilities more attractive over the long term. Because the results did not appear to be conclusive, TransCanada stated that it would continue to study these alternatives, and whether storage could provide a partial or full replacement of firm service tendered ("FST") service. Upon completion of these studies in the Spring of 1991, new proposals for loss of unit protection may be filed.

TransCanada has provided evidence to show that the build-up of the proposed facilities will provide some short-term Western Section excess capacity, and that this will provide at least partial loss of unit protection during the 1991/92 winter season.

Views of Interested Parties

Eastern Canadian distributors continued to support the need for loss of unit protection on TransCanada's Western Section. Intervenors such as Consumers', GMi, Union and ICG (Ontario) maintained that the protection was needed to avoid possible FS curtailments of up to 4 $10^6m^3/d$ (140 MMcfd) for a forecast period of 14-23 winter days. Although they did recognize that some partial coverage would exist for the 1991/92 winter, these parties were anxious for TransCanada to develop a least-cost alternative to provide full coverage.

Consumers' and GMi argued that the cost of additional looping facilities could be offset by fuel savings and toll revenue from interruptible service. Consumers' noted that it is prepared to await the outcome of TransCanada's study of alternatives and that it supports the use of the most cost-effective means. However, Consumers' requested that the Board make a finding that loss of unit protection is required to enable TransCanada to provide reliable service under foreseeable conditions.

GMi argued that the need to avoid over-building should not prevent construction of those facilities required to provide firm service. Loss of critical unit protection was especially important for GMi because the record demonstrated that the utility cannot now get the assured service on TransCanada which it has a right to. Because its storage and peak shaving capabilities are fully used, GMi needs 100 per cent of its FS entitlement. GMi stated that if TransCanada is unable to meet its own FS obligations, GMi in turn would have difficulty in providing firm service to its customers. GMi stated that because there will not be adequate coverage for its FS requirements on TransCanada during the winter of 1991-92, it might have to curtail some of its customers. GMi requested that the Board direct that loss of unit protection be made available first to existing shippers in 1991-92 on a priority basis, and then to new shippers as it is available. GMi also asked that the Board direct TransCanada to operate its system so as to reduce risk of loss of critical units.

Union stated that it accepts TransCanada's position that volume build up on the Western Section means there is less need for specific loss of unit protection for 1991-92. However, Union believed that the Board should endorse the concept of loss-of-critical-unit protection and should instruct TransCanada both to continue its studies and to include some mechanism in its next facilities hearing.

The Canadian Petroleum Association ("CPA") opposed the construction of loss of unit protection facilities unless TransCanada can demonstrate that the economic benefits outweigh the costs.

Views of the Board

The Board notes that no substantial new evidence, over that provided in GH-1-89, was introduced to support the need for looping facilities to provide Western Section loss of unit protection. The Board remains of the view that during this period of significant pipeline expansion, loss of unit protection for the Western Section is not needed. Some degree of short-term under-utilization of the facilities should provide sufficient extra capacity to deal with compressor unit outages, as evidenced by the partial coverage already forecast to develop during the 1991/92 winter. Infrequent curtailments of deliveries in the order of one to two percent should be manageable within the system infrastructure through cooperation among the companies. It is also noted that many of the parties who support the need for additional facilities are also concerned about the risk of pipeline under-utilization.

The Board encourages TransCanada to review the need for loss of unit protection on certain segments of its system, and to develop the least-cost options available to meet such a requirement. The maximized use of downstream storage and load-balancing services such as FST could be more cost-effective than upstream capital additions, and may address the concerns of eastern Canadian distributors regarding system reliability. The Board does not agree with GMi's suggestion that existing shippers be given some form of priority during a system curtailment situation because, in the Board's view, such a distinction would amount to unjust discrimination.

22.7 Capital Cost Estimates

TransCanada presented evidence that in the course of estimating construction costs, it assessed the impact of a large pipeline expansion program through discussions with other pipeline companies and contractors. TransCanada argued that more accurate estimates can only be made as the start of the work approaches when a more definite overall national level of pipeline construction activity can be determined.

TransCanada is aware of the potential for overruns. This is principally due to the high level of pipeline activity, the size of the proposed expansion and the fact that it is scheduled over a period of two years rather than the usual one -year period. To assess the risk of cost overruns TransCanada performed a risk analysis using a Monte Carlo Simulation. According to TransCanada, the objective of the simulation was to provide a general indication as to the appropriateness of the cost estimates. The results showed a 25 percent probability of exceeding 105 percent of the direct cost estimates. TransCanada is satisfied that this probability of overrun is reasonable due to the size of the expansion program and it also believes that an incentive to control its construction costs exists under the current system (this is further discussed in Chapter 27 of these Reasons).

Views of Other Parties

The results from the risk analysis were questioned by CPA who were concerned with the accuracy of the construction cost estimates, the factors considered in the risk analysis, the variables used as input to the simulation program and the inter-relation between these variables as well as the high probability of overruns.

PanCanadian supported TransCanada by expressing its opinion that TransCanada's recent revision of the cost of facilities showing a decline from the previous estimates of $2.6 billion to $2.4 billion indicated that the cost estimates are being prepared with a view to reliability.

Views of the Board

For the year 1989, the actual per unit pipeline cost was within four percent of TransCanada's estimate. The Board believes that it is difficult to estimate pipeline construction costs much more accurately than this given the magnitude of the expansions being undertaken, the length of the construction schedules and the high level of pipeline construction throughout the country. Accordingly, the Board is satisfied that TransCanada has provided its best possible estimate given the information available at this stage of the expansion project.

Chapter 23
Land Use and Environmental Matters

23.1 Board Requirements

23.1.1 Early Public Notification

During 1990, the Board released its Memorandum of Guidance dealing with early public notification of proposed energy projects. The intent of that Memorandum of Guidance was to provide for public input during the planning and development stage of the project. This then would be incorporated into application proposals to the Board. It was anticipated that providing early public notification of proposed applications and timely public input would improve the Board's regulatory process.

In accordance with the Board's Memorandum of Guidance regarding early public notification, TransCanada:

(i) sent information packages to municipalities, provincial government agencies and local interest groups of which it was aware;

(ii) twice ran public notice advertisements of the proposed facilities in newspapers during the period from 13 December 1989 to 12 January 1990; and

(iii) replied to correspondence and telephone contacts with parties responding to its public notice program. TransCanada indicated that it is its policy to maintain liaison with agencies having an interest in proposed new facilities in order to address their concerns during the finalization of project design, scheduling, construction and restoration.

Views of the Board

In the Board's view, TransCanada has conducted a satisfactory early public notification program.

23.1.2 Requirements of the Act in Respect of the Routing of New Pipeline Facilities

Section 52 of the Act provides that the Board may issue a certificate in respect of a pipeline if it is satisfied that the pipeline "is and will be required by the present and future public convenience and necessity". This section also provides that, in considering an application for a certificate, "the Board shall take into account all such matters as to it appear to be relevant ...". One such matter that the Board considers to be relevant is the general route proposed for the pipeline.

If the Board is satisfied with the proposed general route of a particular loop section of pipeline and issues a certificate in respect of it, the pipeline company must, prior to commencement of construction, submit to the Board Plans, Profiles and Books of Reference ("PPBR") which, among other things, lay out the detailed route of the pipeline segment. Construction of the pipeline cannot take place unless the Board approves the PPBR.

The Board may exempt a pipeline from the requirement of PPBR approval under section 58 of the Act. TransCanada applied for such an exemption in respect of all the pipeline loop sections applied-for in its 1991/92 facilities application, including the Iroquois Extension. This extension, however, has since been approved by Certificate of Public Convenience and Necessity No. GC-78 issued in Connection with TransCanada's Partial Facilities Application. Subsequently, the Board issued Order XG-13-90 which exempted TransCanada from filing PPBR's for all of the loop sections in the Partial Facilities Certificate, including the Iroquois Extension.

23.2 Land Use

23.2.1 Route Selection

TransCanada has applied for a total of 1189.8 km of line pipe, consisting of 79 loop sections in the Provinces of Saskatchewan, Manitoba, and

Table 23-1

TransCanada Proposed 1991/1992 Facilities
New Land Requirements
(1991 Construction)

Loop Description	Loop Section	Length	Permanent Easement		Temporary Workspace	
			Width	Length	Width	Length
		(km)	(m)	(km)	(m)	(km)
Saskatchewan						
4th Loop						
MLV 4 + 11.4 km to MLV 5	Cabri (1)	17.9			30	17.9
MLV 6 + 13.0 km to MLV 7	Cabri (1)	16.3			30	16.3
MLV 18 + 11.6 km to MLV 19	Vibank (1)	19.7			30	19.7
5th Loop						
MLV 2 to MLV 2 + 13.2 km	Burstall (2)	13.2	20	13.2	20	13.2
MLV 5 to MLV 6	Cabri (2)	25.0	20	25.0	25	25.0
MLV 6 to MLV 6 + 17.9 km	Cabri (2)	17.9	20	17.9	20	17.9
MLV 9 to MLV 9 + 9.7 km	Herbert (2)	9.7	20	9.7	20	9.7
MLV 13 to MLV 14	Moose Jaw (2)	23.6	20	23.6	20	23.6
MLV 14 to MLV 15	Moose Jaw (2)	27.9	20	27.9	20	27.9
MLV 15 to MLV 15 + 6.7 km	Moose Jaw (2)	6.7	20	6.7	20	6.7
MLV 17 to MLV 17 + 9.7 km	Regina (2)	9.7	20	9.7	20	9.7
MLV 25 to Sask./Man. Border	Moosomin (2)	2.9	20	2.9	20	2.9
Manitoba						
4th Loop						
MLV 29 + 5.1 km to MLV 30	Rapid City (1)	19.0			30	19.0
MLV 39 to MLV 41	Winnipeg (1)	18.5			30	18.5
5th Loop						
Sask./Man. Border to MLV 25 + 14.4 km	Moosomin (2)	11.5	20	11.5	20	11.5
MLV 30 + 7.9 km to MLV 30 + 18.2 km	Rapid City (2)	10.3	20	10.3	20	10.3
MLV 34 to MLV 36	Portage La Prairie (2)	9.8			20	9.8
MLV 36 to MLV 37	Portage La Prairie (2)	31.8	20	31.8	20	31.8
2nd Loop						
MLV 41 + 3.6 km to MLV 41 + 24.7 km	Ste. Anne (2)	21.1	20	21.1		
MLV 43 + 12.3 km to MLV 44	Sandilands (2)	13.3	15/20/25	6.1	10	7.8
MLV 44 to MLV 44 + 16.4 km	Sandilands (2)	16.4	25	1	10	15.8
MLV 45 + 14.8 km to Man./Ont. Border	Camp Lake (2)	3.6	25/30	3.6		
Ontario						
2nd Loop						
Man./Ont. Border to MLV 46	Camp Lake (2)	0.9	25	0.9		
MLV 46 + 5.6 km to MLV 47	Camp Lake (2)	22.6	20	22.6		
MLV 47 to MLV 47 + 11.4 km	Camp Lake (2)	11.4	20	11.4		
MLV 55 + 10.0 km to MLV 56	Dryden (2)	5.2	20	5.2		
MLV 56 to MLV 57	Dryden (2)	24.9	25/27.4	3.6		
MLV 57 + 7.0 km to MLV 57 + 8.4 km	Dryden (2)	8.4	20	4.1	10	4.3
MLV 59 to MLV 59 + 22.3 km	Martin (2)	15.3	15/25	13.9		
MLV 66-2 to MLV 67-2	Thunder Bay Shortcut (2)	22.9	15	22.9		
MLV 72-2 to MLV 73-2	Thunder Bay Shortcut (2)	20.6	20	14.5	15	6.1
MLV 73 to MLV 73A	Thunder Bay Shortcut (2)	5.0			15	5.0
MLV 76 to MLV 76 + 17.6 km	Macdiarmid (2)	6.4	20/42.7	5.6		
MLV 77 to MLV 78	Jellicoe (2)	14.0	15/20	6.1	10	5.2

Table 23-1 (Cont'd)

TransCanada Proposed 1991/1992 Facilities
New Land Requirements
(1991 Construction)

Loop Description	Loop Section	Length	Permanent Easement		Temporary Workspace	
			Width	Length	Width	Length
		(km)	(m)	(km)	(m)	(km)
MLV 78 to MLV 79	Jellicoe (2)	26.3	20	11.2	10	15.1
MLV 83 to MLV 83 + 11.0 km	Lydia Lake (2)	11.0	20	4.3	15	6.7
MLV 84 to MLV 84A	Klotz Lake (2)	10.4	20	1.7	15	6.5
MLV 84A to MLV 85	Klotz Lake (2)	27.1	20	0.2		
MLV 85 to MLV 85 + 14.9 km	Klotz Lake (2)	14.9	27.4	4.8		
MLV 87 + 15.1 km to MLV 87 + 20.7 km	Shekak River (1)	5.6			15	5.6
MLV 89 to MLV 91	Hearst (2)	30.8	12.2/27.4	9.0	15	15.0
MLV 92 to MLV 93	Mattice (2)	31.1	27.4	0.6	15	31.1
MLV 97 + 13.1 km to MLV 99	Fauquier (1)	17.9			15	14.05
MLV 99 + 26.5 km to MLV 100	Cochrane (1)	5.1			15	5.1
MLV 100 + 12.9 km to MLV 101	Cochrane (1)	15.9			15	15.9
MLV 101 to MLV 102	Cochrane (2)	11.6	21.3/27.4	2.7	15	8.9
MLV 103 to MLV 104	Monteith (2)	17.4	27.4	12.8	15	2.6
MLV 104 to MLV 104 + 14.1 km	Monteith (2)	14.1	27.4	14.1		
MLV 105 to MLV 106	Ramore (2)	23.3	15.2/30	12.6	15	5.1
MLV 106 to MLV 106 + 17.9 km	Ramore (2)	17.9	27.4/42.7	11.2	15	0.7
MLV 108 to MLV 109	Swastika (2)	22.5	27.4	21.8		
MLV 109 to MLV 109 + 13.5 km	Swastika (2)	13.5	27.4	4.8	15	7.1
MLV 110 + 8.4 km to MLV 111	Haileybury (2)	23.6	27.4/42.7	0.6		
MLV 111 to MLV 111 + 24.7 km	Haileybury (2)	24.7	20/42.7	3.8		
MLV 112 to MLV 114	Marten River (2)	19.1	20/25	6.3		
MLV 114 to MLV 114 + 16.8 km	Marten River	16.8	25	2.5		
North Bay Shortcut 1st Loop						
MLV 1201 to MLV 1202	North Bay (1)	12.5			20	12.5
MLV 1202 to MLV 1202 + 22.6 km	North Bay (1)	22.6			20	22.6
MLV 1206 to MLV 1207	Deux Rivieres (1)	26.8			20	26.8
MLV 1211 to MLV 1212	Pembroke (1)	21.4			20	21.4
MLV 1212 to MLV 1213	Pembroke (1)	15.9			20	15.9
MLV 1213 to MLV 1213 + 12.6 km	Pembroke (1)	12.6			20	12.6
MLV 1217 to MLV 1217 + 11.4 km	Stittsville (1)	11.4			20	11.4
	Total	**1027.2**		**457.8**		

Table 23-2

TransCanada Proposed 1991/1992 Facilities
New Land Requirements
(1992 Construction)

Loop Description	Loop Section	Length	Permanent Easement		Temporary Workspace	
			Width	Length	Width	Length
		(km)	(m)	(km)	(m)	(km)
Saskatchewan 5th Loop						
MLV 6 + 17.9 km to MLV 7	Cabri (2)	11.4	20	11.4	20	11.4
MLV 9 + 9.7 km to MLV 9 + 19.5 km	Herbert (2)	9.8	20	9.8	20	9.8
MLV 15 + 6.7 km to MLV 15 + 18.5 km	Moose Jaw (2)	11.8	20	11.8	20	11.8
MLV 17 + 9.7 km to MLV 18	Regina (2)	16.7	20	16.7	20	16.7
MLV 22 to MLV 22 + 8.4 km	Grenfell (2)	8.4	20	8.4	20	8.4
Manitoba 5th Loop						
MLV 25 + 14.4 km to MLV 27	Moosomin (2)	17.3	20	17.3	20	17.3
MVL 30 + 18.2 km to MLV 31	Rapid City (2)	6.8	20	6.8	20	6.8
MLV 37 to MLV 37 + 9.9 km	Portage La Prairie (2)	9.9	20	9.9	20	9.9
Ontario 2nd Loop						
MLV 61 + 23.8 km to MLV 62	Upsala (1)	8.0				
MLV 93 to MLV 93 + 3.3 km	Mattice (1)	3.3			15	3.3
North Bay Shortcut P/L						
MLV 1202+22.6 km to MLV 1203	North Bay (1)	6.0			20	6.0
MLV 1203 to MLV 1203+10.2 km	North Bay (1)	10.2			20	10.2
MLV 1207 to MLV 1207+16.1 km	Deux Rivieres (1)	16.1			20	16.1
MLV 1213+12.6 km to MLV 1214	Pembrooke (1)	16.8			20	16.8
MLV 1217+11.4 km to MLV 1217+21.5 km	Stittsville (1)	10.1			20	10.1
	Total	**162.6**		**92.1**		

Ontario. The location, length and land requirements for each of the loop sections are found in Table 23-1 for 1991 construction and Table 23-2 for 1992 construction.

All proposed loop sections fall either within or adjacent to existing easements, except for two minor deviations in the Camp Lake and Ramore loop sections. Two loop sections, Haileybury and Marten River, are presently subject to the Bear Island Land Claim.

23.2.1.1 Facilities Within Existing Easements

In TransCanada's view, new facilities located within existing easements and requiring only temporary workspace do not present any route-related issues. This applies to facilities totalling 337.3 km, including the fourth and fifth loop sections in Saskatchewan and Manitoba: Cabri, Moose Jaw, Vibank, Rapid City, Portage La Prairie and Winnipeg; the second loop and North Bay Shortcut sections in Ontario: Shekak River, Fauquier, Cochrane, Mattice, North Bay, Deux Rivieres, Pembroke and Stittsville. One proposed loop section of 8.0 km, Upsala, requires neither new easement nor temporary workspace. These loop sections are identified in Tables 23-1 and 23-2 with the number (1).

Views of the Board

In the Board's view, TransCanada's plan to utilize existing easements with associated temporary workspace is a sensible one.

23.2.1.2 Facilities Located Adjacent to Existing Easements

Where new facilities could not be located on existing easements due to easement width constraints, TransCanada proposed that they be located adjacent to the existing easements provided that environmental, engineering, construction and safety concerns were adequately met.

New facilities in this category are identified in Tables 23-1 and 23-2 by the number (2) and include the fifth loop sections in Saskatchewan and Manitoba: Burstall, Cabri, Herbert, Moose Jaw, Regina, Grenfell, Moosomin, Rapid City and Portage La Prairie; and, the following second loop sections in Manitoba and Ontario: Ste. Anne, Sandilands, Camp Lake, Dryden, Martin, Thunder Bay Shortcut, MacDiarmid, Jellicoe, Lydia Lake, Klotz Lake, Hearst, Mattice, Cochrane, Monteith, Ramore, Swastika, Haileybury, and Marten River. Total length of the above-noted loop sections is 845.0 km and the length of the required new easement is 549.9 km.

Views of the Board

The advantages associated with installing new facilities adjacent to existing easements are recognized by the Board. The Board concurs with TransCanada's rationale for installing the proposed new looping facilities adjacent to existing easements and the general routes proposed by TransCanada for those loop sections are accepted by the Board.

23.2.1.3 Facilities Located Adjacent to Existing Easements With Minor Deviations

Two loop sections proposed by TransCanada - Camp Lake and Ramore - are to be situated adjacent to existing easements, with the exception of a minor route deviation in each.

TransCanada's preferred general route for Camp Lake involves a deviation of 1.5 km from MLV 45 + 15.1 km to MLV 45 + 16.6 km. The reasons provided for this choice of route are:

- (i) the existence of rugged, rocky slopes and rock outcrops, with steep cliffs south of the existing line along what would normally have been the preferred route;
- (ii) the existence of several sharp bends in the existing right-of-way;
- (iii) the requirement for extensive grading, removal, handling and disposal of waste material; and,
- (iv) the deviation requires a narrower right-of-way than would be required for a loop adjacent to the existing easement and would require less construction time.

TransCanada concluded from an environmental, construction and safety standpoint that a deviation was preferable to an adjacent route for the aforementioned section of the Camp Lake loop.

Technical, construction and safety-based concerns also caused TransCanada to propose a 6.8 km deviation from MLV 105 + 6.4 km to MLV 105 + 13.2 km along the Ramore loop section. Reasons cited were:

(i) the terrain along the existing right-of-way is a rugged, bouldery till with shallow bedrock for most of its length, in addition to the presence of a wetland from MLV 105 + 12.9 km to MLV + 16.0 km;

(ii) the alignment of the two existing pipelines crosses a 115 Kilovolt (kV) hydroelectric transmission line, Highway No. 11 and the Ferguson Highway. Utilizing the existing right-of-way would require approximately six undercrossings of existing pipelines; and

(iii) the proposed deviation would avoid several sharp side bends in the existing alignment, six undercrossings of the existing pipelines, two line crossings of a hydroelectric transmission line, crossing Highway No. 11 between the two existing pipelines, and is 700 m shorter.

TransCanada prepared comparisons between the normally preferred route and the proposed deviation, demonstrating that the environmental impacts of each are similar and mitigable.

Bear Island Land Claim

Proposed facilities between MLV 110 + 13.8 km and MLV 114 + 10.5 km (Haileybury and Marten River Loops) fall within the Bear Island Land Claim which is now being considered by the Supreme Court of Canada. Until such time as a decision is rendered, new easements cannot be obtained or registered. The Crown may, however, issue a Licence of Occupation which, although it cannot be registered, would permit a new pipeline through the Bear Island Land Claim area. TransCanada has sent information packages and the environmental assessment report for the proposed loops to the Teme-augama Anishnabal Band Council, and plans to consult with the Band Council about specific concerns and appropriate mitigation prior to construction.

During the hearing, TransCanada indicated that it had not yet received a licence of occupation from the Ontario Ministry of Natural Resources ("MNR"), but did not anticipate any problems. TransCanada undertook to keep the Board apprised of the status of the Bear Island Land Claim.

Views of the Board

Given the importance of environmental, construction, engineering and safety considerations, the Board concurs with TransCanada's proposed general routes for the Camp Lake and Ramore deviations.

With respect to the Bear Island Land Claim, the Board realizes that acceptable land acquisition arrangements would have to be finalized with MNR before construction could commence. TransCanada would be required to submit to the Board any land acquisition agreements negotiated with MNR.

23.2.2 Land Requirements, Temporary Work Space and Notifications

Land Requirements

The Board has had a long-standing concern about the potential impact of land requirements for pipeline construction (fee simple and easements) upon affected landowners. As it has in the past, TransCanada provided the Board with schematics of the land requirements for each loop location, a description of its existing easements along with the pipeline location within those easements, and the terrain conditions.

(i) Fee Simple Land

TransCanada indicated that all proposed compressor and metering facilities would be constructed on TransCanada's existing fee land.

(ii) Easements

Easements ranging in width from 12.2 to 42.7 m are required by TransCanada along the 79 proposed loop sections.

Temporary Work Space Requirements

TransCanada requires a 10 m to 30 m width of temporary workspace for machinery movement, for the storage of soil, and to ensure that no environmental or landowner considerations are

jeopardized. This is in accordance with TransCanada's Pipeline Construction Specifications (1990).

Notifications

TransCanada filed a preliminary line list setting out those areas where new easements and/or temporary workspace would be required, and indicated that this list will be updated as new information is obtained. TransCanada will submit a second sequential listing identifying owners who have been served with notices of proposed acquisition as required by section 87 of the Act.

Views of the Board

The Board finds that TransCanada's anticipated requirements for easements and temporary work space are reasonable and justified. With respect to easements, the Board encourages TransCanada to serve section 87 notices of proposed acquisition on all applicable owners at the earliest opportunity. With respect to temporary work space, as long as TransCanada's acquisition of same continues to be a short-term commercial transaction that does not create an interest in land, section 87 of the Act does not apply.

23.2.3 Exemptions from Paragraphs 31(c) and 31(d) and Section 33 of the Act

In its application, as amended, TransCanada requested, inter alia, that the applied-for loop sections be exempted, pursuant to section 58 of the Act, from the provisions of paragraphs 31(c) and 31(d) and section 33 thereof. Such exemptions would relieve TransCanada from the necessity of filing PPBR for Board approval.

Views of the Board

In deciding whether or not to exempt facilities from the provisions of paragraphs 31(c) and 31(d) and section 33 of the Act, the Board has been mindful of the rights of neighbouring landowners who might be affected by the proposed construction. The Board is of the opinion that due to the nature of the facilities' locations, i.e., on existing easements or new easements adjacent thereto, it is unlikely that those landowners would be adversely affected in the long run by the proposed construction.

However, in order to protect the interests of the owners of lands proposed to be acquired by TransCanada, the Board is only prepared to exempt the facilities from the provisions of paragraphs 31(c) and 31(d) and section 33 of the Act on condition that all necessary option or easement agreements be executed by such landowners prior to the commencement of construction.

23.3 Environmental Matters

23.3.1 Environmental Assessment Reports

In support of its GH-5-89 application, TransCanada submitted environmental assessment reports for facilities proposed to be constructed in Saskatchewan, Manitoba, Northern Ontario (Volumes 1 and 2), North Bay Shortcut and Southern and Eastern Ontario.

TransCanada adopted the recommendations contained in those assessments to prevent or mitigate adverse environmental impacts resulting from the project. TransCanada also indicated that it would apply standard mitigative procedures and techniques given in its revised Pipeline Construction Specifications (1990). General environmental policies and procedures would be followed as described in TransCanada's Environmental Protection Practices Handbook (1986).

TransCanada's environmental assessment reports provided information on soils, agricultural capability/productivity, hydrology, vegetation, fisheries, wildlife, forestry, heritage resources, recreation and environmentally sensitive areas. An Environmental Issues List ("EIL") which included recommended practices and procedures to prevent or mitigate specific environmental impacts, was provided for each of the proposed pipeline loops.

23.3.2 Agriculture

Loss of agricultural productivity was identified as one of the potential environmental issues associated with the construction of the new facilities. During construction, immediate effects

can include loss of crop production and interruption of drainage. Effects which may persist after construction are those associated with ground disturbance caused by ditching, soil storage and handling, and vehicular traffic during construction. Impacts often include decreased soil fertility, increased subsoil compaction, increased stoniness of the topsoil and increased tendency to erode due to the destruction of the protective vegetative layer.

TransCanada's standard practices relating to the preservation/restoration of agricultural productivity were outlined in its application. Specific recommendations included adequate separation of topsoil and subsoil, accurate topsoil salvage and replacement, chisel cultivation and subsoiling, and an adherence to wet-weather shutdown policy.

23.3.3 Watercourse Crossings

The proposed pipeline looping projects cross a number of watercourses which could be adversely affected as a result of construction-related activities. Those activities include clearing and grading, trenching, installation of flow diversions, back-filling, hydrostatic testing and related activities such as equipment maintenance and waste disposal. The most serious impacts could result from increased concentrations of sedimentation downstream from the construction area.

TransCanada outlined a number of standard mitigative measures to be followed for all watercourse crossings to limit potential environmental impacts associated with those crossings. As a normal course of action, TransCanada submitted that it would have its contractor minimize the duration of instream activity, maintain ditch plugs for as long as possible at the streambanks to prevent the flow of silt-laden ditch water into the watercourse, minimize streambank vegetation clearing and re-establish streambanks and riverbottoms to their original contours.

TransCanada also developed site-specific procedures such as timing windows for instream construction activities to avoid fish spawning and migration periods. Affected approaches and banks are to be seeded and fertilized following construction. Other construction procedures including crossing methods and mitigation measures are to be submitted prior to construction to the Ontario Ministry of Natural Resources so that the MNR can review that information with TransCanada.

23.3.4 Hydrology/Leachate Migration

TransCanada indicated in its assessment of the North Bay Shortcut Facilities that there was a potential for leachate to migrate from the dump located about 115 m north of the Deux-Rivières Loop and at the county landfill site in the Township of Bromley (located 650 m north of the Pembroke Loop). TransCanada held discussions with the Pembroke District Office of the Ministry of the Environment ("MOE"). Its consultant discussed the matter with representatives of the Bromley and McNab Townships and MOE Pembroke District. As necessary, TransCanada agreed to conduct field work prior to construction to confirm direction of groundwater movement and the related potential for leachate contamination.

23.3.5 Stewartville Cedar Swamp

In its assessment, TransCanada indicated that the Pembroke Loop traverses the Stewartville Cedar Swamp. TransCanada submitted that pipeline construction would only result in minor localized impacts to wetland vegetation in the swamp as temporary workspace is cleared and as excavated material is temporarily stored in the area adjacent to the trench.

With respect to orchid populations that have been identified in the swamp, TransCanada submitted that the greatest concentrations of those orchid populations occur well south of the area to be directly affected by pipeline installation. TransCanada noted that it already has an existing pipeline right-of-way (30 m) through the northern fringe of the Stewartville Swamp. TransCanada, therefore, believes that, since the previous construction was accomplished without significant environmental impact, the new project should provide similar results. According to TransCanada, there would be enough room on the disturbed right-of-way for the second pipeline. New disturbance would be limited to 200 m x 20 m temporary workspace or 0.5 ha of the swamp's total area of 13 ha.

TransCanada expects only very local and limited impacts to the Stewartville Swamp given that the local hydraulic regime had not been affected by the previous pipeline installation. TransCanada agreed to restore existing drainage patterns after pipeline installation. Adherence to TransCanada standard mitigative measures for construction on waterlogged soils, as outlined in its Pipeline Construction Specifications (1990) and its Environmental Protection Practices Handbook (1986) would ensure that impacts during construction and installation are minimized.

MacNamara Field Naturalists Club

The MacNamara Field Naturalists Club ("MFNC") expressed a number of concerns about the proposed construction through the Stewartville Swamp. MFNC specifically wanted assurance that TransCanada would not expand the existing cleared area through the swamp, nor allow construction to alter water levels or to affect water quality in the swamp.

23.3.6 Heritage Resources

TransCanada provided information on heritage resources for the looping sections in Saskatchewan, Manitoba and Ontario. TransCanada indicated that, prior to construction, it would submit detailed heritage resources impact assessments for proposed looping projects in Saskatchewan to the Saskatchewan Parks, Recreation and Culture, Heritage Branch.

In Manitoba, TransCanada noted in its assessment report that there is a high potential for heritage resources finds in the area adjacent to the Assiniboine River (between MLV 34 + 7 km to about MLV 36 + 10 km). Manitoba Heritage Branch specifically recommended that TransCanada's field work include an examination of the Broughton's Creek, Seine River, Birch River and Whitemouth River pipeline crossing areas. TransCanada undertook to further examine those sites and the area of high archaeological potential between MLV 43 + 19 km to MLV 43 + 21 km. TransCanada also agreed to then submit a heritage resources impact assessment to Manitoba Culture, Heritage and Recreation, Historical Resources Branch. If additional sites were located, the contractor would be required to cease operations, and/or a qualified archaeologist would be called in to assess the situation and to decide (in conjunction with Manitoba Heritage Branch) what further action might need to be implemented.

In Ontario, TransCanada's archaeological consultants undertook assessments of the proposed looping sections to identify areas/zones and specific locations with a high potential for the recovery of archaeological remains. TransCanada indicated that it would carry out heritage resources surveys involving aerial and full scale reconnaissance prior to construction, and in the event that finds are unearthed, immediate measures would be taken to protect the site. Provincial authorities would then be contacted for an official assessment.

23.3.7 Environmental Inspection

In order to address the implementation of the project specifications and the various recommendations submitted in the environmental assessment, TransCanada indicated that it will retain environmental inspectors throughout the construction of the project. Those inspectors will help to ensure that all environmental requirements and commitments made during the hearing or developed through discussions with property owners and government agencies are being implemented.

Concerns of the Ontario Pipeline Coordination Committee ("OPCC")

Counsel for the Ministry of Energy for Ontario, acting on behalf of the OPCC, addressed environmental matters at the hearing. TransCanada and the OPCC, through a process of consultation and negotiation, have attempted to identify and resolve many concerns involving provincial responsibilities. As a result of this process with the OPCC, TransCanada made 11 undertakings. These include a number of commitments such as conducting sediment analysis of any dredged material where open water disposal is planned, protecting water intakes and water supplies, monitoring water wells within 100 m of centreline of the pipe where blasting is required and providing the MNR with construction details of proposed watercrossings 30 days prior to construction. TransCanada also agreed to provide the Chairman of the OPCC with copies of all post-construction and as-built reports for review. The OPCC requested that the Board

embody those undertakings in the terms and conditions of any certificate to be issued.

23.3.8 Views of the Board

After considering the environmental information contained in TransCanada's application and evidence adduced at the hearing, the Board is of the view that if the proposed environmental protection measures are implemented, the project would create only minimal environmental impacts of a local and temporary nature.

Environmental issues associated with the proposed construction and the recommended mitigation measures were clearly set out in TransCanada's EIL. The EIL should assist TransCanada in focussing its inspection efforts during construction and implementing an effective environmental monitoring program.

Undertakings given by TransCanada to the OPCC during the hearing covered areas such as protection of water intakes and water supplies, blasting requirements, disposal of dredged material, construction plans for proposed water crossings, and prior notification of Ontario personnel. The Board intends to recommend to the Governor in Council that any certificate include a general condition requiring TransCanada to adhere to those undertakings.

With respect to TransCanada's plan to loop its existing pipeline through the Stewartville Cedar Swamp in Ontario, the Board is of the view that impacts associated with that crossing would be insignificant. The greatest concentration of orchid populations known to exist in that Swamp occur well south of the area directly affected by the pipeline route. The Board notes that TransCanada will limit the area of disturbance to the extent possible and will restore existing drainage patterns after pipeline construction through the area. The Board is of the view that TransCanada's proposed mitigative measures should adequately address the concerns expressed by the MacNamara Field Naturalists Club. The Board also notes that TransCanada will hold a pre-construction environmental seminar with contractors to inform them of the measures to limit impacts on the Stewartville Swamp.

With respect to heritage resources in Saskatchewan, Manitoba and Ontario, the Board will require TransCanada to file the results of its surveys prior to construction, including proposed mitigative measures for areas where heritage resources have been identified.

The Board requires TransCanada to implement the various policies and recommendations set out in the application and its environmental reports, including the EIL. The information contained in the EIL should provide a focus for inspection during construction and provide TransCanada with a useful data-base from which to develop and implement an effective environmental monitoring program. TransCanada is also required to implement all undertakings made to the Board during the hearing. Those measures, if properly applied throughout construction, should result in a high standard of environmental protection and right-of-way rehabilitation.

So that it might determine whether the environmental objectives have been achieved, the Board requires TransCanada to file, for Board approval, a post-construction environmental report within six months of the date that leave-to-open is granted. The report should address all of the environmental issues that have arisen up to that time. The report should also discuss the status of each issue and the measures to be implemented for the resolution of any outstanding issues.

The Board requires TransCanada to file a similar report by 31 December following each of the first two full growing seasons after construction.

Chapter 24
Economic Feasibility of the Proposed Expansion

24.1 Introduction

In Volume 1 of these Reasons for Decision, the Board expressed the view that the economic feasibility of the proposed expansion is most appropriately addressed through a determination of the likelihood of the facilities being used at a reasonable level over their economic life and a determination of the likelihood of the demand charges being paid. In section 3.2.1 of Volume 1, the Board indicated that an evaluation of the following factors should provide a good indication of whether this is likely to occur:

(1) evidence that there is likely to be a sufficient long-term supply of gas to keep the pipeline fully utilized over its economic life;

(2) evidence on the long-term outlook for gas demand in the market region to be served;

(3) evidence on the potential competition to gas supplies delivered via TransCanada's system from:

- (i) competing supplies of natural gas;
- (ii) competing energy sources; and
- (iii) competing gas transportation systems;

(4) evidence on the individual gas contracts underpinning the expansion, including:

- (i) evidence that the demand charges will be paid;
- (ii) evidence as to the adequacy of project-specific supply for the proposed expansion;
- (iii) evidence that adequate gas transportation arrangements exist or will exist both upstream and downstream from the TransCanada system;
- (iv) evidence that all appropriate regulatory approvals in both Canada and the United States will be in place prior to construction of the new facilities; and
- (v) evidence on the financial integrity of the parties to the individual gas sales contracts underpinning the facilities expansion;

(5) the risks associated with the new gas sales, including regulatory risks in all other jurisdictions, allowing for the nature of the market and any previous experience with the market; and

(6) the likelihood of a toll increase caused by the expansion resulting in reduced demand for firm service on the system.

24.2 Submission by TransCanada

24.2.1 Long-Term Gas Supply

Relying on the Sproule study[1], TransCanada submitted that adequate natural gas supply exists to ensure continued utilization of the total pipeline capacity in the long-term.

More specifically, TransCanada noted that the Sproule study concludes there is more than adequate long-term gas supply available from currently-producing areas in the WCSB to utilize all existing and applied-for facilities. In addition, discovered reserves in the frontier areas and the ultimate potential of gas reserves in the frontier areas should be available to meet part or all of any future shortfall in productive capacity.

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1. Sproule Associates Limited, "The Future Natural Gas Supply Capability of the Western Canada Sedimentary Basin", January 1990, Exhibit B-12. A detailed discussion of the Sproule study appears in Chapter 19 of these Reasons.

TransCanada argued that the Sproule study is reliable; its methodology has been accepted by the Board in its Reasons for Decision in GH-1-89; and it is consistent with the Geological Survey of Canada's estimate of ultimate reserves potential.

24.2.2 Long-Term Market Outlook

With regard to the long-term outlook for gas demand in the domestic market regions to be served by the proposed expansion, TransCanada submitted that evidence had been provided to demonstrate that the new domestic volumes represent normal growth. TransCanada noted that the Board had concurred with this view in its Partial Facilities Decision (GH-5-89 Reasons for Decision, November 1990, Volume 2, p.5) where it stated:

> *The Board is satisfied that long-term requirements of 2 920 $10^3m^3/d$ (103 MMcfd) exist for domestic FS shippers and that, likewise, there is a requirement for 980 $10^3m^3/d$ (34.6 MMcfd) for domestic STS shippers. These requirements support the facilities requested in the partial facilities application.*

With respect to long-term demand in the export markets to be served by the proposed facilities, TransCanada submitted that extensive examinations of the U.S. Northeast, including a study undertaken by Foster Associates[2], indicate that there is substantial demand for additional natural gas supplies to meet both existing and new LDC and cogeneration loads.

TransCanada argued that the combined effect of market growth, concerns about the adequacy of U.S. domestic deliverability over the long term, the constraints on interstate pipeline capacity and environmental concerns all lead to the conclusion that the U.S. Northeast is a long-term market for Canadian gas delivered via the TransCanada system.

2. Foster Associates, Inc., "Prospective U.S. Natural Gas Markets (Update)", December 1989, TransCanada's Response to National Energy Board's Information Request Item No. 4. A detailed discussion of the Foster report appears in Chapter 20 of these Reasons.

24.2.3 Potential for Competition

TransCanada also addressed the factor of potential under-utilization of its system due to competing supplies of natural gas, competing energy sources and competing gas transportation systems.

With regard to competing supplies of gas in the Canadian market, TransCanada indicated it had demonstrated that U.S. natural gas imports could increase without impacting on the design volumes. TransCanada argued that increases in imports are more reflective of the inability of gas consumers in Eastern Canada to access incremental supplies due to capacity constraints on its system than the competitive appeal of U.S. natural gas supply.

TransCanada expressed confidence that any firm capacity on its system would be competitive with imports and, thus, its system would not be "unloaded". Concerns surrounding the long-term deliverability of U.S. gas and limits on pipeline capacity to bring U.S. supplies into the domestic market also reduce the risk of competition from alternative gas supply sources.

With respect to gas competition in the export markets to be served, TransCanada referred to its evidence on the long-term outlook for gas demand as demonstration of the competitiveness of Canadian gas in the U.S. Northeast.

In addressing the question of competition from alternate fuels, particularly fuel oils, TransCanada noted that, in Eastern Canadian markets, natural gas is projected to continue to have a competitive advantage over fuel oil for the next 20 years. In Quebec, gas demand is expected to share the projected growth in total energy demand with fuel oil.

TransCanada indicated that the relatively low market share for natural gas in the U.S. Northeast is due to limitations on pipeline capacity and to supply uncertainties as well as to competition with fuel oil. Price advantages of gas over fuel oil are resulting in incremental demand for gas in the heating load sector. In addition, the power generation market represents a significant incremental load for natural gas, particularly

because environmental factors may limit the use of alternative energy sources in this sector.

Further, TransCanada argued that the current instability of international oil markets provides a competitive advantage for natural gas.

With respect to competing gas transportation systems, TransCanada argued that it had been demonstrated that its system is the most economical way of serving the U.S. Northeast market with Canadian gas. TransCanada believed that the potential risk of more than one pipeline being contracted to serve one market was small and that the FERC Open Season process had resolved the issue of competing proposals to serve Northeast market demands.

24.2.4 Individual Gas Contracts

Regarding the individual gas contracts underpinning the expansion, TransCanada noted that the Board had determined in its Reasons for Decision on the Partial Facilities application that long-term requirements exist for the domestic shippers. The Board had also expressed satisfaction with the supply arrangements outlined by the domestic shippers and confidence in the ability of these shippers to pay the demand charges over the terms of their contracts.

TransCanada indicated that, with respect to the export contracts underpinning its proposed expansion, it had included in the application only those projects which met strict criteria for mature projects and that it was confident of the integrity of the contracts underpinning the proposed expansion. More particularly, TransCanada noted that transportation Precedent Agreements had been executed with all export shippers and that Letter Agreements or Financial Assurances had been acquired from all prospective shippers. These agreements provided assurance that all associated demand charges would be paid.

In TransCanada's view, the financial integrity of the proposed shippers had been addressed through the negotiation of Financial Assurances.

24.2.5 Risks Associated With New Gas Sales

TransCanada indicated that it had conducted an extensive analysis of the risks associated with the U.S. Northeast in an effort to put these risks into perspective and to mitigate their impact on the system. In TransCanada's view, the combined effect of market growth with expected decline in Lower 48 production and limitations on U.S. pipeline capacity result in the U.S. Northeast being a sizeable market opportunity for Canadian producers. TransCanada noted that the potential risk associated with the power generation market must be placed in perspective. Cogeneration projects account for about 27 percent of the volumes associated with the expansion; each project is relatively small; financial assurance agreements ensure that at least 12 months of demand charges will be paid; and many of the projects included in the application were well advanced. TransCanada concluded that the long-term contractual arrangements underpinning each of the projects mitigated the commercial risk of the expansion.

With regard to regulatory risk, TransCanada noted the support of U.S. regulators and politicians for the expansion.

24.2.6 Toll Increase and Reduced Demand

TransCanada argued that the toll increase associated with the expansion, under the rolled-in methodology, would not be a major factor in affecting the competitive fuel relationships in the markets served over the forecast period. Recent discussions held by TransCanada with existing and new shippers reaffirmed the expectation that gas will flow at forecast levels. TransCanada believed that any decrease in energy demand induced by economic conditions would be at the expense of discretionary energy supplies; that is, spot gas or other fuels. In the longer term, higher oil prices would offset any potential decline in gas demand.

In summary, TransCanada submitted that the support of producers and shippers for the expansion, expressed through their commitment of gas and the signing of long-term gas purchase and transportation agreements is a critical market indicator of economic feasibility.

24.3 Views of Intervenors

Further to the Board's decision in the first phase of the GH-5-89 proceedings, several intervenors

expressed views on the Board's general approach to determining the economic feasibility of a facilities expansion.

In a general statement, the CPA expressed the opinion that the recent decision of the Board with respect to toll methodology and economic feasibility is a step towards re-regulation of the gas industry. In the CPA's view, the combination of rolled-in tolling and no economic feasibility test is a large step away from a market-oriented, deregulated industry.

CPA claimed that, having chosen, as an effect of its decision, to assume the entire weight of facilities decisions and to decline to shift a significant portion of these decisions to market participants, the Board has taken on an onerous responsibility. In future, the Board must weigh all evidence very carefully before making any determination that particular facilities or projects should proceed. The Board must also ensure that applicants and beneficiaries of projects provide satisfactory evidence upon which to determine that projects are economic and in the public interest.

Consumers' expressed the view that the only means now available to guard against the adverse consequences of a facilities expansion is a careful and thorough assessment of individual projects.

GMi also noted that, in light of the Board's decision on economic feasibility, it is essential that the question of new facility utilization be studied carefully since, with rolled-in tolls, all shippers will bear the cost of under-utilization or over-building. GMi asked that the Board especially note that the Canadian market has limited flexibility to absorb capacity built for the export market.

In addressing the risk of facilities underutilization, Union argued the Board should take a careful, critical look at each of the projects underlying TransCanada's application. Union believes the Board would protect shippers on the TransCanada system and minimize the risk of under-utilization by "weeding out" weaker projects. Union argued that, in light of the evidence on long-term demand, the Board cannot have confidence that, if some of the projects underlying TransCanada's application do not prosper or do not renew after their initial term, the facilities will be used to serve other customers.

Union emphasized that, because the cost of the new facilities will be recovered from all shippers on the TransCanada system, it is essential that gas actually flow through the pipeline, not merely that demand charges be paid. Union submitted that confidence facilities will be "used and useful" should be a critical factor in the Board's assessment of economic feasibility.

In this regard, Union emphasized the importance of contractual assurances that gas contracted for will be taken and urged the Board to deny certification of facilities required to provide service to shippers who have failed to provide binding assurances of takes.

IPAC expressed the view that facilities need to be economically justified prior to certification. The examination by the Board of each of the components of a facilities application is particularly important given the Board's dismissal of any form of quantitative economic feasibility test. IPAC, APMC, KannGaz and PanCanadian all indicated the overall evidence demonstrates that the economic feasibility factors defined by the Board have been satisfied.

24.4 Views of the Board

The Board has carefully evaluated the factors that are listed in Section 24.1 in order to assess the economic feasibility of TransCanada's proposed expansion. This section provides the Board's findings in respect of each of those factors. Note that these Views, in assessing the economic feasibility of the proposed facilities, make use of findings that the Board has already made in respect of various of the issues from the GH-5-89 proceeding.

Long-Term Gas Supply

The Board concurs with TransCanada that there will be an adequate natural gas supply to ensure sufficient utilization of the TransCanada system, including the proposed expansion. As discussed in Chapter 19, the Board considers it reasonable to expect that production from alternative sources would be available at competitive prices to supplement any deficiency in supply capability from the WCSB that might occur beyond the

period examined in the Sproule study which was submitted by TransCanada. The Board has found on the basis of the overall supply evidence, the market evidence and the specific contractual arrangements related to the proposed expansion, that the overall utilization of the TransCanada system in the longer term is not likely to be affected significantly by contract terminations by WGML's producers.

Long-Term Market Outlook

As discussed in Chapter 20, the Board finds TransCanada's assessment of long-term domestic requirements to be reasonable and concurs that the proposed capacity destined for domestic purposes will be utilized.

With respect to the export market, the Board concurs that there is a growing market for gas in the U.S. Northeast and finds that there is a role in that market for Canadian supplies, at least over the period of the contracts underpinning the expansion. The Board has reached this conclusion based on the evidence it heard regarding contracts that have been signed and commercial agreements that have been made. The Board has also found that Canadian gas could continue to compete for Northeast markets beyond the initial contract period, using the facilities under consideration.

Potential for Competition

Chapter 20 also reviewed the evidence on potential competition to deliveries via TransCanada's system from competing supplies of natural gas, alternate energy sources and other gas transportation systems.

The Board is of the view that imports of natural gas from the U.S. should not pose a major threat to the utilization of the proposed capacity destined for domestic purposes.

With respect to the potential for competition to exports, the Board has found that the U.S. Northeast is a highly competitive market, dependent on residential conversion, increased use of gas in the power generation sector and maintenance of a competitive position with respect to other fuels. However, the Board believes that the contractual and commercial arrangements associated with the expansion will ensure utilization of the proposed facilities for at least the initial contract period.

Individual Gas Contracts

(i) Demand Charges

Precedent agreements have been executed in respect of transportation for the new requirements underpinning the proposed expansion and there are provisions for payment of demand charges. The Board is satisfied that the contractual chain associated with each of the individual requirements will obligate payment of demand charges. Furthermore, TransCanada, by requiring financial assurances, has assessed the financial integrity of potential shippers in order to satisfy itself that demand charges will in fact be paid.

(ii) Project-Specific Supply

In addition to evidence regarding overall supply, the Board considered evidence on project-specific supply provided in respect of new requests for service associated with the proposed expansion. The evidence on project-specific supply for new requests for domestic service was addressed in the GH-5-89 Reasons for Decision, Volume 2 - Partial Facilities; the evidence on project-specific supply for new exports has been considered in Chapters 3 through 17 of these Reasons.

The Board finds the project-specific supply arrangements associated with new service requests to be adequate to support TransCanada's proposed facilities. As noted in sections 3.5 and 7.5, the Board shares the concerns expressed by Union and Consumers' that provisions allowing unilateral or bilateral termination of contracts can be construed as constituting a short-term supply. On a stand-alone basis, contracts containing such provisions would not be considered adequate to support a facilities expansion. However, the Board is satisfied overall with respect to the project specific supply supporting the facilities application since the total volumes subject to a termination provision comprise less than 10 percent of the throughput of the proposed facilities.

(iii) Upstream and Downstream Transportation Arrangements

The Board has carefully examined the transportation agreements that were filed in respect of the new requirements. Precedent Agreements were provided for most of these new requirements and, based on its review of these agreements, the Board is satisfied that adequate transportation arrangements to transport the new volumes exist or will exist both upstream and downstream of the TransCanada system.

(iv) Regulatory Approvals

The evidence showed that, in most cases, the required regulatory approvals in Canada and the United States are in place, or are well along the approval process. Furthermore, as indicated in Chapter 20, the Board will include, in the certificate that it will recommend to the Governor-in-Council be issued, a condition requiring TransCanada to file, prior to commencement of construction, evidence that all necessary Canadian and U.S. federal regulatory approvals have been granted. This condition will ensure that the regulatory approvals are in place before TransCanada commences construction.

(v) Financial Integrity

The financial integrity of the parties to the individual gas sales contracts associated with an expansion is relevant to the determination of the economic feasibility of that expansion. Depending on the type of financial assurances entered into for a given service request, the potential failure by a party to pay demand charges pursuant to the gas sales contract could have an effect on the payment of transportation demand charges on the TransCanada system. However, no parties expressed concerns about the financial integrity of any of the parties to the gas sales contracts in the GH-5-89 proceedings. Furthermore, as more fully discussed in Chapter 21 of these Reasons, TransCanada is in the best position to assess the financial integrity of the parties to the transportation agreements associated with a facilities expansion.

Risks Associated with New Gas Sales

The Board has carefully examined the contracts associated with the new requirements, and is satisfied that they are generally solid and that there are minimal risks associated with the new gas sales.

In its GH-5-89 Reasons for Decision, Volume 1 - Tolling and Economic Feasibility (page 12), the Board expressed its view that the U.S. Northeast is not a new market, nor a distinct market relative to Ontario, Quebec, or U.S. Midwest markets.

Also in Volume 1 (page 36), the Board noted that TransCanada, as well as being one of the beneficiaries of pipeline expansion, is also in a position to determine and influence the risk of under-utilization of pipeline capacity. The Board was sympathetic to the views of parties that TransCanada should bear some risk of underutilization of its facilities and noted that TransCanada was in fact exposed to some risk in this regard.

The only issue that was raised during the proceeding in relation to regulatory risk associated with new gas sales was in respect of the possibility of unrecovered demand charges stemming from a claim of force majeure in the gas sales agreements between ANE and its repurchasers, as a result of U.S. regulatory action with respect to demand charge pass-through. In Chapter 21, the Board found that this risk could be dealt with by considering, at a future toll proceeding, the disposition of any unrecovered demand charges stemming from a claim of force majeure authorized to be recorded in a deferral account.

Toll Increase and Reduced Demand

The Board's views on the evidence regarding the demand for transportation services on the TransCanada system are found in Chapter 20. TransCanada assessed the impact of the toll increase of $0.10/GJ (later revised to $0.09/GJ) resulting from the expansion and concluded that there would be little impact on its forecast of system requirements.

The Board agrees with TransCanada that the toll increase does not affect significantly the results of TransCanada's forecast. As noted in the GH-5-89 Reasons for Decision, Volume 1 - Tolling and Economic Feasibility (page 11), the forecast 1992/93 toll for the Eastern Zone is actually lower

than it was in July 1987. In fact, the forecast 1995 toll, with the full impact of the proposed GH-5-89 facilities included, would be lower in real terms than it was two decades ago.

Decision

On the basis of the information provided by TransCanada and the export applicants associated with the proposed facilities, the Board is satisfied that the proposed expansion of the TransCanada system is economically feasible.

Chapter 25
Facilities Decision

The Board has reviewed the supply and market requirements, as well as the contractual arrangements of the new firm service requests associated with TransCanada's facilities application. The Board has also considered the overall supply available to the TransCanada system, the projected demand for natural gas in Eastern Canada and the U.S. Northeast, the design of the facilities, their potential environmental impacts, and the economic feasibility of the expansion. Most of the expansion remained largely uncontested, with the exception of specific concerns related to service requests totalling less than 15 percent of the proposed increase in system capacity.

The Board is not persuaded that it should certificate less than the applied-for increase in pipeline capacity, as recommended by Consumers' and Union. The Board recognizes these parties' concerns that certain proposed firm transportation service requests may not proceed as envisaged during the hearing. However, in light of TransCanada's stated intention to file an application for further facilities expansion to provide service beginning 1992/93, the likelihood of the capacity certificated as a result of this hearing not being fully used is extremely low.

Before commencement of construction of a portion or all of any certificated facilities, TransCanada will be required to submit updated system requirements, including new service requests, as well as the associated engineering flow schematics.

On the basis of the evidence before it, the Board has found that there is a unsatisfied demand for long-term firm transportation capacity on the TransCanada system, and that there is adequate supply to satisfy that demand. The Board has also found the design of the proposed facilities to be appropriate, and their environmental impacts to be mitigable, subject to the conditions outlined in Chapters 22 and 23 of these Reasons. Furthermore, the Board has found the expansion to be economically feasible.

In view of the foregoing, the Board has found that the proposed facilities are and will be required by the present and future public convenience and necessity. Therefore, the Board will recommend to the Governor in Council that a certificate be issued. The certificate will be subject to the conditions outlined in Appendix VI.

Upon issuance of a certificate, the Board will exempt the facilities, pursuant to section 58 of the Act, from paragraphs 31(c) and 31(d) and section 33 thereof, subject to the condition outlined in section 23.2.3 of these Reasons.

PART IV MATTERS

Section 71 Application

26.1 Application Summaries

26.1.1 Indeck Gas Supply Corporation

By application dated 21 December 1989, Indeck Gas Supply Corporation applied:

(i) pursuant to subsection 71(2) of the Act for an Order of the Board requiring TransCanada to receive, transport, and deliver 225 $10^3m^3/d$ (8.0 MMcfd) of gas for Indeck on a firm basis for a 15-year term from Empress, Alberta to the proposed export point at Chippawa, Ontario;

(ii) pursuant to subsection 71(3) of the Act for an Order of the Board requiring TransCanada to provide adequate and suitable facilities for receiving, transmitting, and delivering the gas offered by Indeck for transmission from Empress, Alberta to the proposed export point at Chippawa, Ontario; and

(iii) pursuant to section 20 of the Act for such other order or orders granting such further or other related relief as to the Board may seem just and proper.

The gas to be transported by TransCanada in compliance with the aforementioned orders would be sold to Indeck Gas Supply Corporation - Indeck-Ilion for use in its cogeneration facility to be constructed at Ilion, N.Y. and exported in accordance with an export licence for which an application was filed and considered by the Board in the GH-5-89 proceedings.

The associated regulatory approvals and contractual arrangements, including those related to the purchase, transportation, and sale of the gas are fully described in Chapter 10 of these Reasons for Decision.

In support of its section 71 application, Indeck set out the following sequence of events:

- In a request for service form, dated 30 December 1988, Indeck requested transportation service on the TransCanada system to Niagara Falls, Ontario commencing 1 November 1991.

- By letter dated 1 February 1989, TransCanada advised Indeck that before further consideration would be given to its request for service, Indeck would be required to file evidence of its gas supply arrangements and an update on the status of the Ilion cogeneration project. TransCanada indicated that this information was required to allow TransCanada to file its "1991 and 1992 Facilities Application" on or about 1 April 1989.

- By letter dated 15 May 1989, TransCanada advised Indeck that it would not be included in the "1991 and 1992 Facilities Application" as TransCanada was of the view that the information provided with respect to gas supply, downstream transportation, regulatory approvals, and thermal energy sales contractual arrangements was inadequate.

- In its "Hearing Order GH-5-89 Directions on Procedure" dated 28 September 1989, the Board advised that prospective Part VI export licence applicants would have until 1 December 1989 to file their applications related to TransCanada's "1991 and 1992 Facilities Application". TransCanada was directed to file its revised "1991 and 1992 Facilities Application" by 15 December 1989.

- In late October and early November 1989, Indeck furnished TransCanada with additional documentation related to the gas purchase and transportation contractual arrangements.

- By letter dated 17 November 1989, TransCanada advised Indeck that the gas supply information furnished by Indeck with respect to its Ilion service request did not comply with the Board's GHW-3-89 Decision[1] and that therefore, Indeck's request for service had been denied.

- On or about 1 December 1989, Indeck's Part VI export licence application was filed with TransCanada. Indeck contended that the gas supply information provided in that Part VI application met the criteria of the aforementioned GHW-3-89 Decision.

Indeck noted TransCanada's position that the requests for service would be included in the 1991 and 1992 facilities application provided these were received by TransCanada by 6 November 1989, and provided the project was sufficiently advanced. Indeck submitted that TransCanada's position was arbitrary and resulted in an anomalous situation whereby an export licence applicant could comply with the Board's procedural directions, by filing its export licence application with the Board by 1 December 1989, but be excluded from the revised 1991 and 1992 facilities application because the evidence filed by 1 December 1989 was incomplete on 6 November 1989.

Indeck indicated that, although the gas purchase and thermal energy sales agreements remained unexecuted as of 6 November 1989, TransCanada had been advised that Trilogy and Indeck had executed a gas supply precedent agreement which was expected to be followed by the execution of a gas purchase agreement after Trilogy's Board of Director's meeting on 16 November 1989.[2] TransCanada was similarly advised that the thermal energy sales agreement had been negotiated and was awaiting execution.

Indeck argued that TransCanada would not incur an undue burden if it is ordered to construct facilities to transport the Indeck-Ilion volumes. Indeck also argued that the granting of its application would allow the Indeck Ilion project to proceed by removing the uncertainty associated with the lack of transportation service. Indeck noted that the Indeck-Trilogy gas sales and purchase agreement provides that if, by 1 October 1991, Indeck has not secured the regulatory authorizations associated with transportation service on the TransCanada system, Trilogy may terminate the agreement prior to 1 November 1991, upon giving ten days notice.

In its argument-in-reply, Indeck reiterated its position that although its section 71 application requests transportation service effective 1 November 1991, Indeck does not expect TransCanada to provide such transportation service prior to TransCanada receiving the necessary regulatory approvals and completing construction of the necessary facilities. Indeck added that its evidence indicates that even if the in-service-date were delayed to 1 April 1993, Indeck would still want the transportation service.

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1. Chapter 3, section A(2) of the Board's GHW-3-89 Reasons sets forth the Board's decision that:

   "In those cases where incremental volumes are included in the application that do not result from normal growth in a shipper's existing market, the Rules will apply as follows:

   i) when specific pools are contractually dedicated to the project, TransCanada is required to provide the gas supply information specified in Part I of Schedule II of the Rules; and

   ii) when specific pools are not contractually dedicated to the project, TransCanada is required to provide the gas supply information specified in Part I of Schedule II of the Rules, with the exception that subparagraph 3(b)(iii) thereof is to be replaced by

   "(iii) a supply/demand balance for each supplier of gas to the project, demonstrating an adequate supply to meet that supplier's commitment to the project;"."

2. The gas purchase agreement was executed on 29 November 1989 and the thermal energy sales agreement on 17 November 1989.

Indeck argued that it takes no comfort from TransCanada's evidence that the Indeck Ilion transportation service request has been included in the 1992/93 queue.

In response to IPAC's position that the granting of Indeck's application would prejudice other prospective shippers, Indeck argued that there has been no evidence filed in this regard and that no one has come forward to claim that such prejudice would occur.

Indeck concluded that its application is the result of having missed TransCanada's 6 November 1989 cut-off-date by a mere ten days, the result of having to wait for Trilogy's Board of Director approval of the gas sales arrangement. Indeck did not believe that the granting of its application would result in setting a dangerous precedent.

26.1.2 Rochester Gas and Electric Corporation

By application dated 15 January 1990, RG&E applied:

(i) pursuant to subsection 71(2) of the Act for an Order of the Board requiring TransCanada to receive, transport, and deliver 453.2 $10^3m^3/d$ (16.0 MMcfd) of gas for RG&E on a firm basis for a ten-year period commencing 1 November 1991, or on such later date as TransCanada can reasonably make such service available, from Empress, Alberta, and from other TransCanada receipt points in Saskatchewan, to the proposed export point at Chippawa, Ontario; and

(ii) pursuant to subsection 71(3) of the Act for an Order of the Board requiring TransCanada to provide adequate and suitable facilities necessary to receive, transport, and deliver the gas offered by or on behalf of RG&E and requiring TransCanada to construct such further facilities as may be necessary for that purpose.

RG&E submitted that it is a combination gas and electricity utility serving Rochester and the surrounding counties in western New York State and that it is dependent upon CNG for the majority of its gas supply, and for all transportation to its citygate.

In an effort to diversify its gas supply and to lessen its dependence upon CNG, RG&E entered into a gas supply contract with Unigas. RG&E noted that under the terms of that contract, RG&E is responsible for contracting for transportation service on the TransCanada system. To this end, RG&E has concluded a precedent agreement with TransCanada for transportation service from Kirkwall to Chippawa, Ontario, which is dependent upon the construction of the Blackhorse Extension facilities. The precedent agreement is for 453.2 $10^3m^3/d$ (16.0 MMcfd) for a term of 15 years from the date of commencement of service, or such shorter term as would result from RG&E commencing to receive service from Western Canada to Chippawa. Therefore, the subject section 71 application relates only to TransCanada capacity upstream of Kirkwall, Ontario.

The gas is proposed to be exported at Chippawa, Ontario for delivery on the yet-to-be-constructed Empire system to RG&E's New York State franchise area, and to be exported in accordance with an export licence for which an application was filed and considered by the Board in the GH-5-89 proceedings.

The associated regulatory approvals and contractual arrangements, including those related to the purchase, transportation and sale of the gas are more fully described in Chapter 16 of these Reasons for Decision.

RG&E submitted that it is not attempting to jump ahead of others in the TransCanada 1991-92 contract year queue, but simply wants to position itself as the last shipper in the 1991-92 queue so that if any of the projects ahead of it in the queue are delayed or are cancelled, it would be able to take advantage of any of the capacity that might become available. RG&E indicated that this positioning is important since all other necessary downstream transportation facilities and arrangements will be completed before the upstream long-haul transportation facilities on the TransCanada system are in place. RG&E argued, therefore, that granting its section 71 application would ensure that, to the extent any new capacity is available in the 1991-92 contract

year, RG&E would be in the queue to avail itself of that capacity.

RG&E indicated the principal factor motivating its section 71 application is that its other regulatory approvals, contractual arrangements, and transportation facilities are well advanced and that service on the TransCanada system remains the last link in transporting the Unigas gas supply to RG&E's system.

RG&E submitted that, were the Board to find that the granting of RG&E's section 71(3) order would cause the extensive redesign of the applied-for TransCanada facilities and thereby cause a delay in the Board's approval of TransCanada's facilities application, it would voluntarily withdraw the section 71(3) portion of its application. RG&E argued, however, that its request represents a relatively small volume of gas that could take advantage of capacity resulting from other applications not going forward.

RG&E submitted that CNG's opposition to RG&E's application stems from CNG's wish to continue as RG&E's major supplier of gas and exclusive supplier of transportation service. RG&E added that CNG has utilized every means available to thwart RG&E's efforts to diversify its gas supply and transportation strategy. With respect to CNG's concern that there is little evidence to establish that the necessary approvals are in place to permit the Unigas gas to flow, RG&E submitted that any order of the Board could be appropriately conditioned in this regard.

RG&E indicated that it would not oppose the Board conditioning the section 71 order upon approval of the Blackhorse Extension and Empire facilities and upon RG&E and TransCanada executing a ten-year FS contract.

In responding to TransCanada, RG&E acknowledged the need for TransCanada to establish deadlines for applications for service to allow it to plan and design its facilities in an orderly and efficient manner. RG&E argued that it had complied with the Board's 15 January 1990 deadline for filing section 71 applications in the GH-5-89 proceedings.

RG&E argued that it should not be relegated to the yet-to-be-filed 1993 facilities application. In this regard, it reiterated its position that it would withdraw its application if TransCanada had to extensively redesign its facilities for service starting in the 1991-92 contract year. However, RG&E was of the view that there is no claim by TransCanada that providing service starting in the 1992-93 contract year would constitute an undue burden.

RG&E dismissed TransCanada's argument that granting the section 71 application would open the door to future applications and would encourage other potential shippers to deliberately miss TransCanada's deadlines and seek recourse of the Board through a section 71 application.

In responding to IPAC's concern that granting the section 71 application would prejudice others in the queue, RG&E noted that no party had come forth to complain. RG&E argued that this might be due to the very limited relief sought by RG&E which, in RG&E's opinion, is unlikely to cause anyone to be bumped from the 1991/92 contract year queue.

26.2 Views of TransCanada

TransCanada argued that it is opposed to both applications since it believes both Indeck and RG&E were validly excluded from the GH-5-89 FAQ.

TransCanada submitted that its refusal to include these two prospective shippers in its facilities application resulted from its need to compile and submit to the Board its facilities application as soon as possible after the release of the Board's GHW-3-89 Decision. TransCanada decided that, in order to enable it to meet a 1 November 1991 in-service date, an amended facilities application had to be filed with the Board in early December 1989. To accomplish that, TransCanada established 6 November 1989 as the due date by which all prospective shippers to be included in the amended facilities application had to file all necessary evidence, including that related to gas supply and contractual arrangements. TransCanada noted the Board's letter dated 3 November 1989 accompanying its 3 November 1989 GHW-3-89 Decision, in which the Board stated that with respect to TransCanada's request that the Board set a due date for parties seeking service commencing 1 November 1991, it was up to TransCanada to determine when prospective shippers must

provide it with the information to enable it to meet its filing schedule. TransCanada submitted that the 6 November 1989 due date was established in accordance with the Board's 3 November 1989 letter.

TransCanada argued that as of 6 November 1989, Indeck's gas supplier Trilogy had not received Board of Director approval for the sale of gas to Indeck, which TransCanada noted was a precondition to the effectiveness of the gas sales agreement between Trilogy and Indeck. With respect to RG&E, TransCanada noted that it likewise had not furnished the gas supply information by the 6 November 1989 deadline in accordance with the Board's GHW-3-89 Decision.

TransCanada submitted that to grant Indeck the section 71(2) relief (i.e., to place Indeck-Ilion in the FAQ with an in-service date identical to that of Indeck Corinth) would result in an in-service date of 1 April 1992, ahead of several other shippers, including Esso, Encogen, Shell and WGML/Elizabethtown. TransCanada noted that most of those projects had earlier request dates than Indeck-Ilion.

TransCanada argued that the Board's 1 December 1989 deadline for filing Part VI export licence applications and TransCanada's 6 November 1989 deadline for filing the necessary information in support of its Part III facilities application, should be viewed as distinct deadlines.

TransCanada submitted that all prospective shippers had ample notice of TransCanada's intention of establishing a Part III deadline upon the release of the Board's GHW-3-89 Decision.

TransCanada indicated that it is not refusing to provide service to either Indeck or RG&E and that it is TransCanada's intention to include these two prospective shippers in its next facilities application for service in the 1992-93 contract year.

TransCanada believed that the two section 71 applications should be denied as a matter of principle. TransCanada noted that to date, the orderly and timely filing of its facilities applications is made possible as a result of the control that stems from the implementation of its queuing procedures. Specifically, TransCanada noted that those procedures[3] provide for a cut-off date for the filing with TransCanada of all project status and evidentiary support documents, including those pertaining to gas supply.

TransCanada argued that to grant the two section 71 applications would send a message to all future prospective shippers that those rules and procedures need not be complied with, and this, in TransCanada's view, would put at risk the orderly and timely filing and consideration of future facilities applications. In this regard, TransCanada submitted that the addition of more pipeline facilities to accommodate the section 71 applicants would require TransCanada to deviate from a practical, manageable program of pipeline and compressor station engineering, procurement and construction, resulting in a less cost-effective construction program. For this reason, TransCanada argued that requiring it to construct facilities for an in-service date of 1 November 1991 for the section 71 applicants would impose an undue burden on TransCanada within the meaning of section 71(3).

26.3 Views of Intervenors

CNG questioned the need for and the timing of the RG&E/Unigas volumes. CNG noted that the Unigas volumes would serve a small part of RG&E's overall gas requirements and, that being the case, it could not be argued that RG&E is dependent upon the Canadian gas supply. CNG submitted that this lack of dependency on the

3. Section 4.2(c) of TransCanada's queuing procedures provides that when TransCanada determines that there is a reasonable expectation of a long-term requirement for a system expansion and that it therefore intends to prepare and to submit an application to the Board for authorization to construct facilities needed to serve "Accepted Requests" in a "Contract Year Queue", TransCanada is to notify each "Service Applicant". The notification, among other things, identifies the date by which the Service Applicant is required to deliver to TransCanada the project status and evidentiary support documentation ("PS/ES Documents"). These documents, which are defined in Appendix C to TransCanada's "Queuing Procedure", have been found by the Board as being required by TransCanada to allow it to prepare and to submit to the Board a Part III facilities application. Document No. 2, Appendix C, page 2 of 8, relates to gas supply.

Canadian supply and the availability of supply alternatives, raises a doubt as to whether the Canadian public interest would be served by requiring TransCanada to construct the necessary pipeline facilities.

CNG supported the argument of TransCanada against approving the RG&E section 71 application.

IPAC argued that section 71 of the Act should be available only under very extraordinary circumstances. IPAC cited the example of where TransCanada and a prospective shipper are unable to agree on the terms and conditions under which TransCanada is to provide transportation service. In this situation, IPAC believed section 71 offered a means for the shipper to have the Board consider and assist in resolving the dispute.

IPAC argued that the granting of the section 71 applications would prejudice those parties in the queue who had complied fully with both the requirements set out in TransCanada's queuing procedures and the deadlines established by the Board and TransCanada.

26.4 Views of the Board

In deciding whether the public interest would be served by issuing the applied-for section 71 orders, the Board must have regard to, among other things, whether TransCanada, in excluding Indeck and RG&E from its 1991 and 1992 facilities application, acted in a fair and reasonable manner, and in conformity with its tariff and with the procedures established by the Board at the time. Similarly, the Board must have regard to whether the denial of the section 71 relief applied for would prejudice the applicants' right to pipeline capacity and thereby jeopardize their export proposals.

The Board believes that TransCanada acted in a fair and reasonable manner in establishing the 6 November 1989 deadline by which prospective shippers were required to file with TransCanada the project status and evidentiary support documentation associated with TransCanada's Part III facilities application. The Board concurs with TransCanada that the orderly and timely preparation and filing of a facilities application necessitates the establishment and observance of certain deadlines. In this regard, the Board is satisfied that TransCanada provided prospective shippers with sufficient advance warning of its intention to establish and enforce the 6 November 1989 deadline. The Board is also satisfied that TransCanada acted in accordance with the Board's advice and in accordance with the established queuing procedures.

While the Board has taken note of the concerted efforts that were made by Indeck and RG&E to comply with TransCanada's filing requirements, and with those established by the Board with respect to GH-5-89, the undisputable fact remains that both prospective shippers failed to meet TransCanada's deadline and were, therefore, justifiably removed from the 1991/92 FAQ.

Furthermore, the Board has not been persuaded by the evidence adduced by Indeck and RG&E that their respective export projects would necessarily be jeopardized by denying them the section 71 relief sought. In this regard, the Board has noted the advanced state of the other aspects of those two projects and the fact that the latest TransCanada queue for service, dated 20 December 1990, shows Indeck and RG&E in the first and fourth positions, respectively, in the queue for service under the heading "Requests to be included in the pending 1992/93 Facilities Application".

26.5 Decision

The Board denies Indeck's and RG&E's applications filed pursuant to subsections 71(2) and 71(3) of the Act.

Chapter 27

Toll Treatment of Cost Overruns

One of the issues considered in the GH-5-89 proceedings (Issue IV-1) was included to address CPA's concern with TransCanada's pattern of variance between forecast and actual construction costs and the impact of these capital cost overruns on tolls and tollpayers. In this regard, CPA proposed a cost control method which would provide TransCanada with an incentive to minimize capital cost overruns.

CPA had previously expressed its concern regarding the accuracy of TransCanada's cost estimates during the RH-3-89 proceedings where it argued that, historically, TransCanada has spent less on capital additions than it had forecast. At that time the Board denied CPA's proposal of adjustments to TransCanada's rate base, but concurred with CPA about the potential for significant variances between forecast and actual capital costs and in-service dates. The Board directed TransCanada to record, in a deferral account, the capital-related cost of service variances (RH-3-89 Tolls - Reasons for Decision - March 1990) for disposition in future toll hearings.

During the course of the GH-5-89 proceedings, CPA expressed concern with the magnitude of the proposed expansion. According to CPA, TransCanada might be under-estimating the capital costs of the applied-for facilities.

CPA believed that there was insufficient incentive for TransCanada to control costs on a project of this magnitude. It was CPA's view that TransCanada should be given an incentive to accept responsibility for cost overruns before the fact rather than by being permitted to adjust the rate base through a deferral account mechanism after the fact.

The incentive scheme proposed by CPA for the GH-5-89 expansion was to pay TransCanada a fee equal to 1.7 times the actuarial value of its exposure for accepting financial responsibility for the equity-financed portion of the capital cost overruns. Two critical elements in the methodology are:

(i) the base value of capital expenditures; and

(ii) the size of the fee to be paid to TransCanada.

Four components are to be considered in the calculation of the base value:

(a) the base estimate in 1989 dollars;

(b) the price escalation factors;

(c) factors totally beyond TransCanada's control; and

(d) changes in the scope of the project.

The payment to TransCanada would equal 1.7 times the actuarial value of the potential overrun which would be determined by a risk analysis similar to the Monte Carlo Simulation provided by TransCanada.

Views of Other Interested Parties on CPA's Incentive Proposal

All parties that expressed a position were opposed to the implementation of CPA's incentive proposal.

TransCanada expressed the view that CPA's proposal is an unnecessary and complicated process. TransCanada submitted that its cost estimates are reasonable and based on the best information available at this early stage in the project and that, historically, forecast and actual costs have been quite close. TransCanada believes that it has an incentive to control its construction costs under the current scheme in that deferring variances between forecast and actual capital costs and disposing of them in future tolls proceedings places the onus on TransCanada to demonstrate the prudency of over-expenditures. TransCanada argued that the existing cost control measures have been

demonstrated to be adequate by its past performance in forecasting costs. TransCanada also believes that CPA's proposal is unfair by not allowing the review of prudency respecting costs to take place after all the facts are available.

APMC and ICG (Ontario) supported TransCanada's submission by expressing their view that the current cost control measures consisting of the deferral account and cost monitoring through certificates containing conditions are appropriate. The deferral account, which would be brought forward for a full review in the normal course of toll proceedings, gives the Board and interested parties the opportunity to determine if the expenditures were prudent.

Views of the Board

The Board was not persuaded that TransCanada has, in fact, had a history of inaccurate cost forecasting and significant overruns.

The Board shares CPA's concern regarding the impact of capital costs on tolls and tollpayers but it notes that the pipeline construction environment has turned out to be more competitive than expected and TransCanada has already reflected this by lowering its cost estimates.

The Board also shares CPA's concern about potential variances between forecast and actual construction costs which could occur due to the magnitude of the proposed expansion project. To address this concern, the Board has already directed TransCanada to record these variances in a deferral account. The Board believes, as do the APMC and ICG (Ontario), that the deferral account and cost monitoring conditions are an appropriate incentive for TransCanada to accurately estimate and control its construction costs.

Decision

The Board declines to adopt CPA's incentive proposal and is of the view that the existing procedure where variances between forecast and actual capital costs, as accumulated in deferral accounts, are monitored and assessed for prudency at future toll proceedings provides sufficient control over TransCanada's capital expenditures.

Chapter 28

Accounting Treatment for the Retirement of Compressor Units

As part of its facilities application TransCanada proposed to retire three compressors; namely Station 9A Plant Unit 2 and Stations 107A and 112A. TransCanada proposed to treat these retirements as "Ordinary Retirements" as defined in subsection 39(1) of the Board's *Gas Pipeline Uniform Accounting Regulations*. TransCanada also informed the Board in its application that the Orenda OT-F-2R Unit at Station 75A1, which was previously approved for treatment as an "Ordinary" retirement in the GH-1-89 Decision, has been continued in service until 1991 in order that the construction of the pipeline looping approved to replace this unit can be undertaken together with adjacent facilities applied for in this application.

The evidence shows that the compressor at Station 9A is a Clark 305 gas turbine installed in 1960. The unit has accumulated in excess of 130,000 hours of operation. TransCanada proposes to retire this unit because of a lack of vendor support, poor performance and concerns about its remaining service life. The Orenda units at Stations 107A and 112A were installed in 1964 and have been in service for 110,000 and 120,000 hours respectively. Due to a lack of spare parts TransCanada began, in 1988, a five-year program to retire the Orenda units. No parties objected to the retirement of these units or to the proposal to treat these retirements as "Ordinary" for accounting purposes.

Views of the Board

The Board is satisfied that there is nothing extraordinary about the proposed retirements. The compressors in question have provided a normal service life.

Decision

The Board approves TransCanada's proposal to treat these retirements as "Ordinary" within the meaning of subsection 39(1) of the *Gas Pipeline Uniform Accounting Regulations*.

Chapter 29

Disposition

The foregoing chapters constitute our Decisions and Reasons for Decision in respect of the applications heard by the Board in the final phase of the GH-5-89 proceedings.

J.-G. Fredette
Presiding Member

A.B. Gilmour
Member

M.J. Musgrove
Member

R. Illing
Member

K.W. Vollman
Member

Ottawa, Canada
April 1991

APPENDICES

Appendix I

List of Issues Considered in the Final Phase of the GH-5-89 Proceedings (Excerpts from Exhibit A-108)

Part III Matters

III-1 The reasonableness of the forecast of requirements for domestic and export sales and transportation service.

III-2 The overall market demand for natural gas in the U.S. Northeast having regard to, among other things:

- the potential for competition for this market from U.S. and offshore (e.g., Sable Island and LNG) natural gas supplies;
- the existing and future overall level of Canadian and U.S. pipeline capacity into the U.S. Northeast relative to projected market demand; and
- potential changes to the toll methodology on the Great Lakes system.

III-3 The impact on domestic natural gas demand of potentially increased imports of natural gas into eastern Canada.

III-4 The potential for lower-than-expected use of the TransCanada system in light of increased competition to TransCanada from other Canadian and U.S. pipelines.

III-5 The appropriate level and cost of incremental capacity on upstream and downstream pipeline systems and the likelihood that such service will be available in a timely manner.

III-6 The appropriateness of providing for loss-of-unit protection commencing on 1 November 1991 by means of a new Limited Interruption Firm ("LIF") service, storage, or constructing facilities.

III-7 The appropriate combination of looping, and compression for the proposed expansion, and the consistency of that combination with the long-term facilities requirements of the system.

III-8 The appropriateness of the location of the proposed looping in light of emerging urban growth and land-use patterns.

III-9 The appropriateness of the general route for the proposed Iroquois extension.

III-10 The potential environmental impacts of the proposed pipeline crossing of the St. Lawrence River near Iroquois, Ontario.

III-11 The appropriateness of not including any provision for advance capacity for the years 1991/92 and 1992/93.

III-12 The reasonableness of construction and material cost estimates for 1991 and 1992, and the appropriateness of measures to be implemented for cost control, having regard to the magnitude of the proposed facilities expansion and the expected level of construction activity in the pipeline sector in North America over that period.

III-13 The economic feasibility of the proposed expansion, having regard to, *inter alia*:

- the impact of building the applied-for facilities on tolls over the forecast period and the effects higher tolls could have on the demand for natural gas;

- the long-term costs of TransCanada's expansion program;

- the extent to which the additional transportation revenues to be received from the proposed new services would recover the costs of providing such services;

- the existence and adequacy of long-term supplies of gas to support the existing and applied-for facilities; and

- other means or methods of determining the economic feasibility of the proposed expansion.

III-14 The appropriateness of the proposed flow split of incremental volumes between the Great Lakes system and the Central Section having regard to:

- the relative economics of expanding the Central Section versus the Great Lakes system;

- the longer-term flexibility with respect to access to alternative markets and pipeline capacity;

- environmental considerations associated with the alternative routes; and

- timing considerations respecting regulatory approvals, construction resources, and the availability of materials affecting the proposed in-service date.

III-15 The question of whether the contractual arrangements associated with those new services supporting TransCanada's applied-for facilities appropriately allocate risk between TransCanada and prospective shippers.

III-16 The appropriate terms and conditions to be included in any certificate or order which may be issued.

Part IV Matters

IV-1 The appropriate toll treatment of variances between forecast and actual construction costs of the proposed facilities.

Part VI Matters

VI-1 The ability of the cogeneration market to utilize the gas volumes contracted, having regard to, *inter alia*:

- regulatory risk at the state and federal levels;

- steam and power purchase obligations;

- long-term assurance of continual takes; and

- alternative supply sources.

Discussion of the Board's Supply Analysis

The Board conducts a review of the applicants' gas supply arrangements to assist it in determining whether the proposed exports are in the public interest. In its assessment of gas supply, the Board examines the contractual arrangements pertaining to supply in order to assess the nature and extent of the supply commitment to the proposed export project. This examination is conducted in conjunction with the review of other elements of the contractual arrangements for the proposed project.

Each export applicant provided estimates of remaining established reserves for those fields from which it intends to supply gas for the proposed export. In addition, some applicants submitted estimates of undiscovered potential for undrilled lands under their control. The Board also conducted geological and engineering analyses of each applicant's gas supply in order to prepare its own estimate of the applicant's marketable gas reserves.

In its evaluation of gas reserves, the Board made use of its gas reserves database, which is maintained and updated on an ongoing basis. The evaluation of gas reserves includes a nomenclature and correlation determination, volumetric studies of new pools, re-examination of developing pools and performance analysis of producing pools. A review and assessment of the ownership and contractual status of all pools included in each of the applications were also conducted.

In recent gas export applications, the supply submitted by applicants has often been comprised in part of a substantial number of single-well pools, many of which are non-producing. Applicants frequently use a full-section assignment for productive area in the evaluation of established reserves for these single-well pools. The full section assignment is often supported by these applicants on the basis that it is standard industry practice to assign full-section areas and that reserves appreciation will occur in some of these pools over time.

The Board's approach to the assignment of reserves for single-well pools is based on its studies on the production performance of small pools. The results of this work were grouped by formation and geographical location within Alberta. The majority of the single-well producing pools were located in eastern and southern Alberta in Lower Cretaceous zones.

The AERCB has also conducted a study of single-well pools and has adopted an approach to area assignments similar to that used by the Board.

Pool area in small pools is often unknown since the pool has only been penetrated by one well and there may not be sufficient geological control to delineate area. The study conducted by the Board indicated that the volumetric calculation of reserves using a full-section area assignment often resulted in an overstatement of the reserves when compared to estimates derived by analysis of production performance. The results of the study suggested that reserves were overstated on average by about 25 percent for lower Cretaceous pools. Considering that many reservoir parameters can be fairly accurately determined, it is usually area or recovery factor that is least well-defined. The Board chose to reduce its estimates of reserves for these pools by making adjustments to the pool area used in the reserves determination.

The Board recognizes that, although it generally makes reserves adjustments primarily by modifying pool area, the recovery factor could alternatively be used to make this adjustment in many cases. The reduced recovery factor often arises because increasing water production results in the premature suspension of these pools (i.e. with the reservoir pressure still relatively high), or because in less permeable reservoirs the net effective productive drainage area may be less than the lateral limits determined based on geological control.

The Board generally applies these results as a guideline only. In those cases where geological or other data are available which indicate that the guidelines are not appropriate, adjustments to the general area assignments are reflected in the Board's reserves estimates.

The Board's approach to assignment of reserves to a discovery well and consideration of possible appreciation of reserves is consistent with the definition of established reserves. This definition makes reference to reserves specifically proven by drilling, testing or production, plus that judgment portion of reserves interpreted to exist from geological, geophysical or similar information, with reasonable certainty. Where the Board has geological or other evidence, from its own data base, to suggest that a larger area assignment is warranted, reserves assigned to the discovery well include an allowance for appreciation. A portion of the area would generally be categorized as probable reserves and discounted by a risk factor. In addition, the Board has in some circumstances given consideration to undiscovered potential where an applicant provides evidence to demonstrate that the potential will be under its control. These estimates are also discounted by an appropriate risk factor.

Estimates of reserves submitted by the applicants in this proceeding were primarily for specific pools distributed throughout most areas and zones in Alberta. Other pools in British Columbia, Saskatchewan, the Yukon and the Northwest Territories made up the balance of reserves. Pool sizes varied from small, single-well pools to very large, established pools. Generally, larger pools tend to have been producing for a considerable period of time, while single-well pools have often not yet been placed on production.

In reviewing marketable gas reserves, the Board evaluated the number, size and distribution of pools for which each of the applicants had submitted estimates of reserves. In some cases, the Board's pool count was different from that of an applicant because the Board amalgamated or segregated pools on the basis of its interpretation of reservoir data. Any reference to pool counts in these Reasons for Decision is based on the Board's analysis. The Board used a pool size of $100\ 10^6m^3$ (3.5 Bcf) for all applicants as a somewhat arbitrary dividing line between small and large pools.

Due to the length of this proceeding the analysis of reserves conducted by the Board, although current at the time of the evaluation, has become somewhat dated. In general, the Board's supply analysis is based on remaining reserves as of year- end 1988, with adjustments to reflect new wells and pools submitted by applicants and certain revisions based on analysis conducted during 1989. The Board recognizes that some revisions in pool reserves may have occurred since year-end 1988 and production since that time is not reflected in its estimates. However, a large proportion of the supply is from non-producing pools so that the use of year-end 1988 estimates of remaining reserves is not expected to be a significant concern with respect to the assessment of available supply for the proposed export applicants.

The Board's estimates of reserves, along with basic deliverability data for each of the pools for which estimates of reserves were submitted by an applicant, were used in preparing productive capacity projections. Productive capacity projections are generally adjusted to reflect an applicant's expected requirements for gas. The adjusted productive capacity is the estimated productive capacity at any point in time, carrying forward for future use the productive capacity resulting from an earlier excess of productive capacity over production. The requirements shown for each of the applicants included in the productive capacity figures are based on a load factor of 100 percent and therefore somewhat overstate each applicant's actual supply needs. To the extent that a lower load factor were to be experienced, productive capacity would be sustained beyond the time the Board's analyses indicate.

The Board is also concerned with the status of an applicant's application to the respective provincial bodies for energy removal authorizations. In the GH-5-89 proceeding all applicants indicated that they had applied for the appropriate removal authorizations.

Appendix III

Cogeneration Plants

Eleven of the 15 export applications reviewed in GH-5-89 involved the sale of gas for use in cogeneration facilities. A twelfth application involved a direct sale to an electric utility for use in its own generation plants (see Table III-1 shown on next page).

Regulations issued under authority of the PURPA require that a cogeneration facility, in order to maintain its status, have a thermal output, as process steam, exceeding five percent of the total energy output of the plant. Also, the total electrical energy plus one-half of the thermal energy output must exceed 45 percent of the total energy fuel input (42.5 percent if the thermal output is greater than 15 percent). Failure to meet PURPA operating efficiencies could cause a cogeneration facility to lose its QF status.

Another criterion that must be met to obtain QF status is that an electric utility's ownership in a QF does not exceed 50 percent.

The PURPA regulations require an electric utility to buy all of the electricity generated by a QF and, unless the electric utility and the QF otherwise agree, to pay the QF not more than the utility's full avoided-cost of producing the electricity.

QF owners and electric utilities may make arrangements for the electric utility to dispatch the total output of the cogeneration facility.

Should a cogeneration facility lose its QF status, neither the PURPA nor the implementing regulations would prevent it from regaining its status once compliance with the criteria for qualification had been restored.

Table III-1

Electricity Generation Projects for which Export Licence Applications were Filed

Gas Applicant	Electricity Generation Project	Capacity (MW)	Electrical Customer(s)	Steam Customer	Annual Volumes (Bcf/yr)
Brymore Energy	Pawtucket	(61.3)	New England Power	Colfax	4.7
Canadian Occidental	Old Bethpage	(79)	Long Island Lighting	---	5.6
Encogen	American Brass	(62)	Niagara Mohawk	American Brass	5.7
FSC Resources	North East	(79)	Niagara Mohawk	Welch Foods	5.8
Fulton	Nestle	(47.4)	Niagara Mohawk	Nestle Foods	4.6[1]
Indeck Corinth	Corinth	(118.7)	Consolidated Edison	International Paper	6.0
Indeck Ilion	Ilion	(54.7)	Niagara Mohawk	E.I. Du Pont	2.6 & 4.5
JMC Selkirk	Selkirk	(79)	Niagara Mohawk	General Electric	8.4
Kamine Carthage	Carthage	(49.9)	Niagara Mohawk	James River II	4.93
Kamine South Glens Falls	South Glens Falls	(49.9)	Niagara Mohawk	James River II	4.93
New England Power (NEP)	Brayton Pont Manchester St. South Street	(430) (450)[2] (100)[3]	NEP NEP NEP	--- --- ---	21.9
ProGas	MassPower	(240)[4]	MMWEC (A) MMWEC (B) Boston Edison WMECo Commonwealth Electric	Monsanto Chemical	9.125

Notes:
1. Nestle will consume 4.6 Bcf annually in the first 10 yrs and 2.3 Bcf annually in the last 4 yrs.
2. Manchester St. is a repowering from 150 MW to 450 MW.
3. South St. is an existing 100 MW station capable of gas/oil firing.
4. Winter rating is 132 MW and summer rating is 103 MW.

Terms and Conditions of the Licence to be Issued to Pawtucket Power Associates Limited Partnership.

1. The term of this Licence shall commence on 1 November 1991 and shall end on 1 November 1993 unless exports commence hereunder on or before 1 November 1993, in which case the term will end on 31 October 2006.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) 362 500 cubic metres in any one day;

   (b) 132 400 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 1 986 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (b) As a tolerance, the amount that may be exported in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Iroquois, Ontario.

Terms and Conditions of the Licence to be Issued to Canadian Occidental Petroleum Ltd.

1. The term of this Licence shall commence on 1 November 1991 and shall end on 1 November 1993 unless exports commence hereunder on or before 1 November 1993, in which case the term will end on 31 October 2006.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) 433 400 cubic metres in any one day;

   (b) 158 200 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 2 373 000 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (b) As a tolerance, the amount that may be exported in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Niagara Falls, Ontario.

Terms and Conditions of the Licence to be Issued to Encogen Four Partners, L.P.

1. The term of this Licence shall commence on 1 November 1991 or the date of first deliveries, whichever is the later, and shall end on 1 November 1993 unless exports commence hereunder on or before 1 November 1993, in which case the term will end 15 years following the commencement of the term of this Licence.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) 424 900 cubic metres in any one day;

   (b) 155 100 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 2 326 600 000 cubic metres during the term of this Licence.

3. Gas exported under the authority of this Licence shall be delivered to the point of export near Niagara Falls, Ontario.

Terms and Conditions of the Licence to be Issued to Esso Resources Canada Limited.

1. The term of this Licence shall commence on 1 November 1991 and shall end on 1 November 1993 unless exports commence hereunder on or before 1 November 1993, in which case the term will end on 31 October 2006.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) 991 500 cubic metres in any one day;

   (b) 362 000 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 5 432 000 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (b) As a tolerance, the amount that may be exported in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Iroquois, Ontario.

Terms and Conditions of the Licence to be Issued to FSC Resources Limited.

1. The term of this Licence shall commence on 1 November 1991 and shall end on 1 November 1993 unless exports commence hereunder on or before 1 November 1993, in which case the term will end on 31 October 2006.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) 453 000 cubic metres in any one day;

   (b) 165 345 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 2 480 175 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

(b) As a tolerance, the amount that may be exported in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Niagara Falls, Ontario.

5. Prior to the commencement of exports, the licensee shall not, without the approval of the Board, replace either its gas supply or market with other gas supply or market.

Terms and Conditions of the Licence to be Issued to Fulton Cogeneration Associates.

1. The term of this Licence shall commence on 1 November 1991 and shall end on 1 November 1993 unless exports commence hereunder on or before 1 November 1993, in which case the term will end on 31 October 2005.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) for the period commencing on 1 November 1991 and ending on 31 October 2001, 326 200 cubic metres in any one day, or 119 000 000 cubic metres in any consecutive twelve-month period ending on 31 October;

   (b) for the period commencing on 1 November 2001 and ending on 31 October 2005, 160 000 cubic metres in any one day, or 58 400 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 1 424 000 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (b) As a tolerance, the amount that may be exported in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Chippawa, Ontario.

Terms and Conditions of the Two Licences to be Issued to Indeck Gas Supply Corporation.

A. With respect to the Indeck Corinth cogeneration facility.

1. The term of this Licence shall commence on 1 November 1991 or the date of first deliveries, whichever is the later, and shall end on 1 November 1993 unless exports commence hereunder on or before 1 November 1993, in which case the term will end 15 years following commencement of the term of this License.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) 459 000 cubic metres in any one day;

   (b) 168 000 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 2 439 000 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

(b) As a tolerance, the amount that may be exported in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Chippawa, Ontario.

B. With respect to the Indeck-Ilion cogeneration facility.

1. The term of this Licence shall commence on 1 November 1991 or the date of first deliveries, whichever is the later, and shall end on 1 November 1993 unless exports commence hereunder on or before 1 November 1993, in which case the term will end 15 years following the commencement of the term of this Licence.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

(a) 210 000 cubic metres in any one day;

(b) 73 000 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

(c) 852 000 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

(b) As a tolerance, the amount that may be exported in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Chippawa, Ontario.

Terms and Conditions of the Licence to be Issued to Selkirk Cogen Partners, L.P.

1. The term of this Licence shall commence on 1 November 1991 or the date of first deliveries and shall end on 1 November 1993 unless exports commence hereunder on or before 1 November 1993, in which case the term will end 15 years and 6 months following the commencement of the term of this Licence.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

(a) 651 500 cubic metres in any one day;

(b) 237 800 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

(c) 3 685 900 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

(b) As a tolerance, the amount that may be exported in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Iroquois, Ontario.

Terms and Conditions of the Licence to be Issued to Kamine Carthage Cogen Co., Inc. and Beta Carthage Inc.

1. The term of this Licence shall commence on 1 November 1991 and shall end on 1 November 1993 unless exports commence hereunder on or before 1 November 1993, in which case the term will end on 31 October 2006.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) 402 250 cubic metres in any one day;

   (b) 139 500 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 2 093 700 cubic metres during the term of this Licence.

3. As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Chippawa, Ontario.

Terms and Conditions of the Licence to be Issued to Kamine South Glens Falls Cogen Co., Inc. and Beta South Glens Falls Inc.

1. The term of this Licence shall commence on 1 November 1991 and shall end on 1 November 1993 unless exports commence hereunder on or before 1 November 1993, in which case the term will end on 31 October 2006.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) 402 250 cubic metres in any one day;

   (b) 139 500 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 2 093 700 cubic metres during the term of this Licence.

3. As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Emerson, Manitoba.

Terms and Conditions of the Licence to be Issued to New England Power Company.

1. The term of this Licence shall commence on 1 November 1991 and shall end on 1 November 1993 unless exports commence hereunder on or before 1 November 1993, in which case the term will end 15 years from 1 November of the year in which exports commenced.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) 1 700 000 cubic metres in any one day;

   (b) 621 000 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 9 308 000 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (b) As a tolerance, the amount that may be exported in any consecutive twelve-month period under the authority of this Licence

may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Iroquois, Ontario.

Terms and Conditions of the Licence to be Issued to ProGas Limited.

1. The term of this Licence shall commence on 1 November 1991 or the date of first deliveries, whichever is the later, and shall end on 1 November 1993 unless exports commence hereunder on or before 1 November 1993, in which case the term will end 18 years and 6 months following the commencement of the term of this Licence.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) 708 200 cubic metres in any one day;

   (b) 258 493 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 4 800 350 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (b) As a tolerance, the amount that may be exported in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Iroquois, Ontario.

5. Licence No. GL-81 will be revoked should the Governor in Council approve this new licence.

Terms and Conditions of the Licence to be Issued to Unigas Corporation.

1. The term of this Licence shall commence on the date of first deliveries and shall end on 1 November 1993 unless exports commence hereunder on or before 1 November 1993, in which case the term will end 10 years following the date of first deliveries.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) 453 200 cubic metres in any one day;

   (b) 165 500 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 1 654 200 000 cubic metres during the term of this Licence.

3. Gas exported under the authority of this Licence shall be delivered to the point of export near Chippawa, Ontario.

Terms and Conditions of the Licence to be Issued to Western Gas Marketing Limited.

1. The term of this Licence shall commence on the date of first deliveries and shall end on 1 November 1993 unless exports commence hereunder on or before 1 November 1993, in which case the term will end 15 years following the first day of the first month succeeding the date that deliveries commence.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) 283 000 cubic metres in any one day;

(b) 103 700 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

(c) 1 552 000 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that may be exported in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

(b) As a tolerance, the amount that may be exported in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Niagara Falls, Ontario.

Facilities Originally Included in TransCanada's Facilities Application Which Have Been Certificated, or Exempted from Certification, prior to Issuance of Volume III of these Reasons

Order or Certificate Number	Date Issued	Pipeline or Looping	Compressor or other Facilities
Order XG-5-90	29 May 1990		14.0 MW Compressor units at Stations 116, 1206 and 1217
Order XG-4-90	28 June 1990	3.3 km from MLV 15 + 23.4 km	
Certificate GC-78 Partial Facilities	22 November 1990	391.4 km of pipeline looping 4.5 km - Iroquois Extension	2 Compressor relocations
Order AO-1-XG-5-90	31 January 1991		Amending Order XG-5-90 substituting Station 88 for Station 116
Order XG-8-91	6 February 1991	1.1 km - Lake Wahtopanah Crossing	
Order XG-11-91	15 March 1991		26.1 MW Compressor unit at Station 116

Appendix VI

Certificate Conditions

1. The pipeline facilities in respect of which this certificate is issued (the additional facilities) shall be the property of and shall be operated by TransCanada.

2. (1) TransCanada shall cause the additional facilities to be designed, manufactured, located, constructed and installed in accordance with those specifications, drawings, and other information or data set forth in its application, or as otherwise adduced in evidence before the Board, except as varied in accordance with subsection (2) hereof.

   (2) TransCanada shall cause no variation to be made to the specifications, drawings or other information or data referred to in subsection (1) without the prior approval of the Board.

3. TransCanada shall implement or cause to be implemented all of the policies, practices, recommendations and procedures for the protection of the environment included in its application, its environmental reports filed as part of its application, its Pipeline Construction Specifications, its Environmental Protection Practices Handbook, 1986, or as otherwise adduced in evidence before the Board in the GH-5-89 proceeding.

4. Unless the Board otherwise directs, TransCanada shall, prior to the commencement of construction of any specific pipeline section referred to in this certificate, demonstrate to the Board's satisfaction that all necessary option or easement agreements have been executed by the landowners through whose property that loop section passes.

5. TransCanada shall file with the Board, at least ten days prior to the commencement of construction, the results of the heritage resource surveys referred to in the GH-5-89 proceeding, including any corresponding mitigative measures.

6. TransCanada shall, at least 10 days prior to the commencement of construction of the additional facilities, file with the Board a detailed construction schedule or schedules identifying major construction activities and shall notify the Board of any modifications to the schedule or schedules as they occur.

7. Unless the Board otherwise directs, TransCanada shall, prior to the commencement of construction of the additional facilities, demonstrate to the Board's satisfaction that:

   (1) in respect of new firm export volumes, all necessary United States and Canadian federal regulatory approvals, including applicable long-term Canadian export authorizations have been granted; and

   (2) with respect to the transportation of new firm volumes on the TransCanada system:

      (a) transportation contracts have been executed;

      (b) all necessary United States and Canadian regulatory approvals have been granted in respect of any necessary downstream facilities or transportation services; and

      (c) gas supply contracts have been executed.

8. Unless the Board otherwise directs, TransCanada shall, prior to the commencement of construction of any of the approved facilities, submit for Board approval:

(1) requirements tables in the same format as Tables 2, 3, and 5 of subtab 1 under tab "Requirements" of Exhibit B-1 from the GH-5-89 proceeding, showing the anticipated base case requirements and those requirements for which condition 7 has been satisfied; and

(2) flow schematics of the TransCanada system demonstrating that those approved facilities which are to be released for construction are necessary to transport the requirements referred to in subsection (1).

9. During construction, TransCanada shall file with the Board monthly construction progress and cost reports, providing a breakdown, by location and facility, of costs incurred during that month, the percentage complete of each activity and an update of projected costs to complete the project.

10. TransCanada shall, within six months of putting the additional facilities into service, file with the Board a report providing:

(1) a breakdown of the costs incurred in the construction of the additional facilities in the format used in Schedules 3 through 29 of subtab 10 under tab "Facilities" of Exhibit B-1 to the GH-5-89 proceeding, setting forth actual versus estimated costs, including reasons for significant differences from estimates; and

(2) the percentage of Canadian content realized in comparison with that estimated in Schedules 31 and 32 of Tab 10 under Tab "Facilities", of Exhibit B-1 to the GH-5-89 proceeding, including reasons for significant differences.

11. TransCanada shall implement or cause to be implemented all of the policies, practices, recommendations and procedures for the protection of the environment included in its application, its environmental reports filed as part of its application, its Pipeline Construction Specifications (1990), its Environmental protection Practices Handbook (1986), its undertakings made to the Minister of Energy of Ontario (Ontario Pipeline Coordination Committee), or as otherwise adduced in evidence before the Board in the GH-5-89 proceedings.

12. TransCanada shall, at least ten days prior to the commencement of construction of the additional facilities, file with the Board a detailed construction schedule or schedules identifying major construction activities and shall notify the Board of any modifications to the schedule or schedules as they occur.

13. (1) TransCanada shall file with the Board a post-construction environmental report within six months of the date that the last leave to open is granted for the additional facilities.

(2) The post-construction environmental report referred to in subsection (1) shall set out the environmental issues that have arisen up to the date on which the report is filed and shall:

(a) indicate the issues resolved and those unresolved; and

(b) describe the measures TransCanada proposes to take in respect of the unresolved issues.

(3) TransCanada shall file with the Board, on or before the

31 December that follows each of the first two complete growing seasons after the post-construction environmental report referred to in subsection (2) is filed:

(a) a list of the environmental issues indicated as unresolved in the report and those that have arisen since the report was filed, if any; and

(b) a description of the measures TransCanada proposes to take in respect of any unresolved environmental issue.

14. Unless the Board otherwise directs, TransCanada shall cause the construction and installation of each of the additional facilities, herein referred to, to be commenced on or before 31 December 1992.